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ABANDONED BUT NOT FORGOTTEN: IMPROPERLY PLUGGED AND ORPHANED WELLS MAY POSE SERIOUS CONCERNS FOR SHALE DEVELOPMENT

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ABSTRACT

This Article addresses the intersection of oil and gas law and environmental law on a topic that has profound significance for the nation's oil industry and for the environment. In this regard, the Permian Basin is experiencing a renaissance that has fundamentally impacted oil production in the United States. Horizontal drilling and hydraulic fracturing now allow the industry to produce in the Permian Basin's unconventional shale formations in ways that were unimaginable a decade ago. But, the hot shale plays within the Permian Basin exist above conventional fields that are littered with a century's worth of abandoned wells. Fracturing new wells near improperly abandoned wells creates a risk of environmental pollution as the fracturing of the shale allows hydrocarbons to migrate within the formation, potentially to an improperly abandoned well.

The American Petroleum Institute (API) recognizes the environmental pollution risks associated with hydraulically fracturing close to an abandoned well and has set forth a detailed report on the best practices that an operator could employ to mitigate this risk, but that proposal overly relies on operator discretion and judgment and lacks transparency to potentially affected parties. The Environmental Defense Fund has issued a model regulatory framework, but that report overly relies on operator actions and bright-line standards. A growing number of state agencies in oil producing states around the nation have issued regulations, but there is considerable divergence in the adopted standards. The academic work on this topic is sparse to non-existence. Thus, this Article fills an important void in the literature at an important moment.

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The goal of any regulatory regime should be to ensure sustainable energy development occurs in a manner that adequately addresses the environmental concerns posed by modern development activities. Because contamination and collateral consequences of pollution can have far-reaching impacts, the public has a vital public policy interest that the regulatory regimes that govern this development require the industry to utilize best practices. The Article proposes that the regulatory agency should use its expertise and operator supplied information to make a fact-based determination of the area of fracturing interest as part of the permitting process for any new well that will be hydraulically fractured. The regulatory agency then would utilize its existing data on well locations to determine what existing wells are sufficiently close to the new well that will be hydraulically fractured and then will set forth requirements for the operator to investigate that well. The regulatory agency can then set forth a remediation proposal for the operator to perform. The Article uses the State of Texas as a model for its suggestions.

The framework set forth in this Article also affords operators with an opportunity to provide their solutions to any regulatory concerns, and also provides other affected parties an opportunity to participate in the well permit process. Thus, the proposed regulatory framework sets forth a transparent and objective regime that does not solely rely on the business judgment of operators. Moreover, by requiring this analysis to be done in a scientific manner and by providing an opportunity for notice to be given to affected parties, the proposal also provides an opportunity for potentially affected parties to take precautionary steps on their own wells. Currently, Texas does not have any explicit requirements with respect to investigation of close proximity abandoned wells in its well permitting process, and the failure to require an upfront investigation creates an unnecessary environmental risk that could be mitigated if addressed upfront.

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INTRODUCTION

Horizontal drilling, coupled with multi-stage hydraulic fracturing, has revolutionized the oil and gas industry.[1] These transformative techniques resulted in the nation experiencing a boom in crude oil production that fifteen years ago seemed unimaginable.[2] In fact, the Energy Information Administration estimates that the U.S. will produce approximately eleven million barrels of oil per day in late 2018.[3] If the U.S. sustains that level of production in 2018, it would represent the highest level of U.S. crude oil production on record.[4]

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1. For the week ending on December 27, 2002, less than 16% of the wells being drilled at that time in the United States were oil wells, and less than 7% of those wells were horizontal wells. Thus, United States onshore activity largely centered on natural gas, and at that time horizontal drilling represented a minor drilling technique. In only fifteen years, the energy industry has been radically transformed by oil development in unconventional shale formations. For the week ending on December 30, 2016, approximately 80% of the wells being drilled in the United States were oil wells, and more than 80% of those wells were horizontal wells. For the rig count information cited above, see *North American Rotary Rig Count* (Jan. 2000-Present), BAKER HUGHES, http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother (last visited July 29, 2018) (see tabs 4 and 5). As of December 30, 2016, more than 92% of the wells being drilled in Texas were oil wells, and more than 80% of the wells being drilled were horizontal wells. *Id.* Horizontal drilling in shale oil formations has revolutionized the oil and gas industry and has become the new paradigm against which existing Texas oil and gas common law principles must be measured. For an overview of horizontal drilling and hydraulic fracturing process, see Monika Ehrman, *The Next Great Compromise: A Comprehensive Response to Opposition Against Shale Gas Development Using Hydraulic Fracturing in the United States*, 46 TEX. TECH L. REV. 423, 428–34 (2014).

2. For a detailed analysis of the economic impact of the Eagle Ford shale production, see THOMAS TUNSTALL ET AL., ECONOMIC IMPACT OF THE EAGLE FORD SHALE 10 (Ctr. for Cmty. & Bus. Research, Inst. for Econ. Dev., Univ. of Tex. at San Antonio, ed., 2013).

3. *See* J. Resnick-Ault, *U.S. Crude Oil Production Hit Record High in November: EIA,* REUTERS (Feb. 28, 2018), https://www.reuters.com/article/us-usa-oil-production/u-s-crude-oil-production-hit-record-high-in-november-eia-idUSKCN1GC2PB (projecting that US will exceed 11 million barrels per day by late 2018); ENERGY INFO. ADMIN., SHORT TERM ENERGY OUTLOOK 5 (2017), https://www.eia.gov/outlooks/steo/pdf/steo_full.pdf ("EIA forecasts U.S. crude oil production to average 10.8 million b/d in 2018, up from 9.4 million b/d in 2017, and to average 11.8 million b/d in 2019." If realized, both of these forecast levels would surpass the previous record of 9.6 million b/d set in 1970.).

4. Tom DiChristopher, *US Oil Output Poised to Hit 10 Million Barrels a Day Next Year, Breaking 1970 Record, EIA Says*, CNBC (June 6, 2017), http://www.cnbc.com/2017/06/06/us-oil-output-to-hit-record-10-million-barrels-a-day-next-year-eia.html.

Historically, wells were drilled as vertically as possible.[5] Thus, oil and gas leases, and drilling regulations, developed in the context of vertical wells.[6] Moreover, under the Rule of Capture,[7] the lessee of a legally-spaced well is not liable to adjacent landowners for drainage of the adjacent tract if the lessee's production is legal and obtained in a non-negligent manner.[8]

In contrast to the historic vertical well paradigm, today's horizontal wells are radically different.[9] Today, a majority of new wells drilled in the United States are horizontal wells completed in unconventional shale formations.[10] These horizontal wells can possess a horizontal drain hole extending more than 7,500 feet away from

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5. *See* 16 TEX. ADMIN. CODE §3.11(a) (2017).

6. *See* JORDAN K. MULLINS, PRODUCTION ALLOCATION ISSUES: NON-PARTICIPATING ROYALTY INTEREST OWNERS IN VERTICALLY AND HORIZONTALLY POOLED UNITS 6 (2014). In the formative years, deviated drilling was referred to as slant-well drilling where drillers tried to hide the fact that the operator was producing from a well that was bottomed on another person's property. The effort to slant well drill gave rise to various tort claims and causes of action. *See* ERNEST E. SMITH & JACQUELINE LANG WEAVER, TEXAS LAW OF OIL AND GAS, § 7.2(A)(2)(a) (2017).

7. *Compare* Barnard v. Monongahela Nat. Gas Co., 65 A. 801, 802 (Pa. 1907) (so holding in vertical well context) *with* Browning Oil v. Luecke, 38 S.W.3d 625 (Tex. App. 2000) (ruling that rule of capture would not apply in the horizontal well context).

8. *See* Elliff v. Texon Drilling Co., 201 S.W.2d 558, 562 (Tex. 1948). The Court made clear that nonliability for drainage did not extend to negligent development. On remand, the negligent lessee was liable to the adjacent landowner for any damage caused to the adjacent tracts due to negligent production. *See also* Texon Drilling Co. v. Elliff, 216 S.W.2d 824, 826 (Tex. Civ. App 1948). The holding in *Elliff* is consistent with a line of Texas cases that holds that a lawful practice that was unreasonable under the circumstances exposes the operator to liability to adjacent landowners who have suffered damage; the protection of the Rule of Capture would not apply in this instance as the rule of capture is a nonliability rule that only protects an operator with respect to reasonable production from a lawful well. *See* Comanche Duke Oil. Co. v. Tex. Pac. Coal & Oil Co., 298 S.W. 554, 560-61 (Tex. Comm'n App. 1927) (excessive amounts of nitroglycerin caused damage to adjacent landowners); Roskey v. Gulf Oil Corp., 387 S.W.2d 915, 919-920 (Tex. Civ. App 1965); Humble Oil & Ref. Co. v. Grucholski, 376 S.W.2d 950, 952 (Tex. Civ. App 1964); Sinclair Oil & Gas Co. v. Gordon, 319 S.W.2d 170, 172 (Tex. Civ. App 195); Klostermann v. Hous. Geophysical Co., 315 S.W.2d 664, 667 (Tex. Civ. App 1958).

9. A growing chorus of scholars and practitioners believe historic oil and gas principles are strained when applied to a variety of scenarios posed in the horizontal drilling context. *See, e.g.*, Bret Wells, *The Dominant Mineral Estate in the Horizontal Well Context: Time to Extend* Moser *Horizontally*, 53 HOUS. L. REV. 193, 197 (2015) ("The thesis of this Article is that the dominant mineral estate doctrine needs to be reformed for the horizontal well context."); Benjamin Holliday, *New Oil and Old Laws: Problems in Allocation of Production to Owners of Non-Participating Royalty Interests in the Era of Horizontal Drilling*, 44 ST. MARY'S L.J. 771, 773 (2013) ("This evolution in the techniques operators use to drill for oil and gas is occurring at speeds that are, at times, beyond our legal framework's ability to keep up."); H. Philip Whitworth & D. Davin McGinnis, *Square Pegs, Round Holes: The Application and Evolution of Traditional Legal and Regulatory Concepts for Horizontal Wells*, 7 TEX. J. OIL GAS & ENERGY L. 177, 213 (2012) ("The continued expansion of horizontal drilling will undoubtedly present new land and legal challenges for the oil and gas industry, its regulators, and the interest owners it affects to resolve.").

10. *See* BAKER HUGHES, *supra* note 1. For an overview of the geological differences between shale formations and conventional formations, see GROUNDWATER PROT. COUNCIL & ALL CONSULTING, MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: A PRIMER 15 (2009).

the drill site.[11] Moreover, today's horizontal wells can be fractured in more than twenty-five stages,[12] and a typical fracturing operation can require as much as 6.3 million pounds of proppant and over 16 million gallons of water per horizontal well.[13] In addition, multiple horizontal wells can be drilled from a single location and possess multiple horizontal lateral legs drilled in stacked fashion[14] or running in multiple different directions from the same surface well site.[15] The pace of change has been remarkable and this transformation testifies to the ingenuity of the upstream oil and gas industry.

The Permian Basin is one of the oldest oil producing basins, yet it is experiencing a renaissance.[16] The first major oil well in the Permian Basin was the Santa Rita No. 1, drilled in 1923 and capped in 1990.[17] The Permian Basin includes the Yates, San Andres, Clear Fork, Spraberry, Wolfcamp, Yeso, Bone Spring, Avalon, Canyon, Morrow, Devonian, and Ellenberger fields.[18] Geologists largely accept that much of the oil and gas produced from the Permian Basin's conventional formations migrated into those conventional fields from the shale formations.[19] Shale formations have long been understood to be the source rock for the conventional

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11. *See* Artem Abramov, *Impact of Downturn on Shale Development: Permian Success Story*, OIL & GAS FIN. J., June 2017, at 16, (see Table 1: Average Completion Intensity and Productivity Metrics For Horizontal Shale Wells). For a comparison of how the intensity of proppants and amount of fracturing fluids has increased in the last four years, see NAT'L ENERGY TECH. LAB.: STRATEGIC CTR. FOR NAT. GAS & OIL, MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: AN UPDATE 47 (2013) (lateral length of one mile), https://www.netl.doe.gov/File%20Library/Research/Oil-Gas/shale-gas-primer-update-2013.pdf; *see also* Larry Chorn, Neil Stegent & Jeffrey Yarus, *Optimizing Lateral Lengths in Horizontal Wells for a Heterogeneous Shale*, SOC'Y PETROLEUM ENG'RS, No. 167692, 2014, at 6, http://www.baroididp.com/premium/tech_papers/source_files/consulting/SPE_167692.pdf (stating that laterals of 6,500 feet optimize cost/benefits of the well and that "[l]aterals in the ± 5,000 ft. range are very common in most North American shale developments").

12. NAT'L ENERGY TECH. LAB., *supra* note 11, at 49–50.

13. *See* Artem Abramov, *supra* note 11, at 16; *see also* Chorn, et al., *supra* note 11; *cf.* NAT'L ENERGY TECH. LAB., *supra* note 11, at 47 (2013) (six million gallons of water was typical in 2013).

14. To accommodate production in different zones, the Railroad Commission rules treat a well that has stacked laterals as a single well for well spacing and well density purposes. *See* 16 TEX. ADMIN. CODE § 3.86(e)(2) (2014) (Tex. R.R. Comm'n, Inclination and Directional Surveys Required).

15. *See* Whitworth & McGinnis, *supra* note 9, at 196–200; *see also* Bruce M. Kramer, *Pooling for Horizontal Wells: Can They Teach an Old Dog New Tricks?*, 55 ROCKY MTN. MIN. L. INST. § 8.01, § 8.02, at 8–8 (2009).

16. *See* Irina Slav, *Texas Set for Another Oil Boom*, OILPRICE.COM (Jan. 28, 2018), https://oilprice.com/Energy/Energy-General/Texas-Set-For-Another-Oil-Boom.html.

17. *See Petroleum Pioneers: Santa Rita Taps Permian Basin*, AM. OIL & GAS HIST. SOC'Y, http://aoghs.org/petroleum-pioneers/west-texas-petroleum/ (last visited June 30, 2018).

18. *Permian Basin Information*, TEX. RAILROAD COMMISSION, http://www.rrc.state.tx.us/oil-gas/major-oil-and-gas-formations/permian-basin-information/ (last visited June 30, 2018).

19. *See Petroleum System of the Upper Permian*, SOC'Y FOR SEDIMENTARY GEOLOGY (Feb. 13, 2013), http://www.sepmstrata.org/page.aspx?pageid=138.

fields that were produced in the Permian Basin in the prior century.[20] Even though the shale formations are resource rich, these formations are substantially less permeable in comparison to the Permian's conventional formations.[21] Consequently, the Permian's shale formations historically were not viewed as promising prospects for commercial development.[22] However, horizontal drilling, combined with hydraulic fracturing, has fundamentally altered this assessment.[23] Under modern drilling techniques, a horizontal wellbore can now travel horizontally a significant distance in a shale formation.[24] As a result, the subsequent hydraulic fracturing of the area immediately surrounding the horizontal wellbore now offers operators the potential to produce vast quantities of oil and gas directly from within the shale formation's newly-created fracture network.[25]

Recent recoverable reserve estimates for the shale formations located in the Permian Basin are astonishing.[26] The Apache Corporation announced that a region it calls the "Alpine High" contains at least 75 trillion cubic feet of natural gas and over 3 billion barrels of oil.[27] A recent U.S. Geological Survey indicates that the shale formations underlying the Wolfcamp formation holds 20 billion barrels of oil and 16 trillion cubic feet of natural gas, making the recoverable reserves found in the shale formation underlying the Wolfcamp field nearly three times greater than those that exist in North Dakota's Bakken shale formation.[28] Representatives of Pioneer Natural Resources have estimated that the cumulative potential recoverable oil that exists in the shale formations underlying the entire Permian Basin could be as much as 75 billion barrels.[29] Thus, modern development techniques

20. *See* U.S. GEOLOGICAL SURVEY, ASSESSMENT OF UNDISCOVERED OIL AND GAS RESOURCES IN THE SPRABERRY FORMATION OF THE MIDLAND BASIN, PERMIAN BASIN PROVINCE, TEXAS, 2017 (2017); *Industry Overview*, Petroleum Servs. Ass'n Can., https://www.psac.ca/business/industry-overview/#upstream (last visited June 26, 2018); *see* Evelina Pagkalou et al., *Why Has Light Tight Oil Production Proven so Resilient in the Permian?*, MCKINSEY ENERGY (Sept. 2016), https://www.mckinseyenergyinsights.com/insights/permian-basin-resilient-lto-production/.

21. *See* Bethany Farnsworth, *Permian Basin Enters Its Second Act*, E&P (Apr. 29. 2015), https://www.epmag.com/permian-basin-enters-its-second-act-789041.

22. *Id.*

23. *Id.*

24. *Id.*

25. *See id.*

26. *See id.*

27. Alex Nussbaum & Joe Carroll, *Apache CEO Crashes Permian Party with 'Giant Onion' Oil Find*, BLOOMBERG NEWS (Sept. 7, 2016, 11:01 PM), https://www.bloomberg.com/news/articles/2016-09-07/apache-discovers-3-billion-barrel-field-in-texas-shale-country.

28. *See* Joe Carroll, *A $900 Billion Oil Treasure Lies Beneath West Texas Desert*, BLOOMBERG NEWS (Nov. 16, 2016, 11:01 PM), https://www.bloomberg.com/news/articles/2016-11-15/permian-s-wolfcamp-holds-20-billion-barrels-of-oil-u-s-says.

29. *See* Joe Carroll, *Texas Shale Driller Sheffield to Retire From Pioneer Natural*, BLOOMBERG NEWS (May 19, 2016, 4:21 PM) http://www.bloomberg.com/news/articles/2016-05-19/texas-shale-driller-sheffield-to-retire-from-pioneer-natural (citing an estimate provided by Scott Sheffield, outgoing CEO of Pioneer Natural Resources, for this estimate).

hold the potential for unlocking massive quantities of oil and gas in the Permian Basin. This potential is already being realized. In 2017, the Permian Basin broke all previous production records due to the expansive growth in shale development.[30] Recent projections forecast that the Permian Basin will produce 5.4 million barrels per day in 2023, and that 41,000 new wells will be drilled in the Permian Basin by that date as well.[31] A new era for re-exploring one of the oldest oil fields in Texas is now dawning.

The renewed development of the Permian Basin is an example of upstream oil and gas developers returning to previously drilled areas in a time where the total number of rigs is declining. U.S. drilling activity has declined from its recent high of 2,026 rigs on November 4, 2011, to 588 rigs as of November 18, 2016.[32] In the Permian Basin, however, activity has been steadily rising over the last year.[33] In fact, drilling activity in the Permian Basin represents more than forty-five percent of all drilling activity in the United States.[34]

For policy-makers, it is important to understand that this dramatic renaissance in the Permian Basin and in the other historic oil basins is occurring in the context of areas that already have been heavily drilled. The Permian Basin is littered with thousands of abandoned wells.[35] Fracturing the resource-rich shale formation close to an abandoned well creates a risk that oil, gas, and hydraulic fracturing fluids could migrate into abandoned wells and cause unwanted pollution. If these inactive and previously abandoned wells were properly plugged when abandoned, then this foreseeable risk is mitigated. However, if previously abandoned wells have not been properly plugged, then their proximity to the area of fracturing interest for

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30. *See* David Hunn, *Permian Basin Oil Production Crushes 1973 Records*, HOUS. CHRON. (Dec. 27, 2017, 7:41 AM), http://www.chron.com/business/energy/article/Permian-Basin-oil-production-crushes-1973-records-12456113.php?utm_source=email&utm_medium=newsletter&utm_campaign=Chron_fuelfix.

31. *See* Jim Burkhard, *Fixing the Permian Mismatch: Upstream Growth and Mid-Stream Takeaway Capacity*, IHS MARKIT (June 13, 2018), https://ihsmarkit.com/research-analysis/fixing-permian-mismatch-upstream-growth-midstream-take-away-capacity.html; Eileen Soreng, *Permian Basin Oil Production to Reach 5.4 MBD in 2023: IHS Markit,* REUTERS (June 13, 2018, 9:13 AM), https://www.reuters.com/article/us-oil-permian-outlook-ihs/permian-basin-oil-production-to-reach-5-4-mbd-in-2023-ihs-markit-idUSKBN1J91W8.

32. BAKER HUGHES, *supra* note 1.

33. *See Rotary Rig Count Summary*, BAKER HUGHES (updated July 20, 2018), http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother (indicating an increase of 102 rotary rigs in the Permian Basin as of July 20, 2018 from the prior year).

34. *See Drilling Productivity Report: Production by Region*, U.S. ENERGY INFO. ADMIN., (Aug. 13, 2018), https://www.eia.gov/petroleum/drilling/archive/2018/08/#tabs-summary-2 (indicating that projected production through August 2018 in the Permian Basin is responsible for 3,333 thousand barrels per day of the 7,327 thousand barrels per day produced in the U.S.); *see also Six Formations Are Responsible for Surge in Permian Basin Crude Oil Production*, U.S. ENERGY INFO. ADMIN. (July 9, 2014), https://www.eia.gov/todayinenergy/detail.php?id=17031#.

35. *See* Kate Galbraith, *Abandoned Oil Wells Raise Fears of Pollution*, N.Y. TIMES (June 8, 2013), https://www.nytimes.com/2013/06/09/us/abandoned-oil-wells-raise-fears-of-pollution.html.

the new well can create environmental contamination and pollution risks. Although the risk of potential migration of oil and gas via abandoned wells has been a known risk for decades,[36] the potential harm posed by improperly abandoned wells is substantially increased if the shale formation is hydraulically fractured near an abandoned well. Absent the hydraulic fracturing of the resource-rich shale formation, its low permeability naturally impedes the migration of hydrocarbons through it to nearby abandoned wells, so this latent risk may not pose an imminent risk absent the hydraulic fracturing treatment.[37] But a negative consequence of substantially enhancing the shale formation's permeability through hydraulic fracturing is that it increases the risk that hydrocarbons can migrate through the new fracture network to a nearby abandoned well and create unwanted environmental contamination.

Consequently, the current reality is that many of the more promising shale formations lie close to conventional formations that were heavily drilled in prior decades, and thus shale development in this context poses special regulatory concerns. The benefits of producing oil and gas from shale formations are undeniable.[38] The pace of the industry's reorientation towards development of shale formations located amid heavily-drilled conventional fields creates unique challenges for both the industry and for the regulatory agencies charged with overseeing the prudent and responsible development of oil and gas resources. The organizing thesis of this Article is that the regulatory framework for shale development must be designed with an appreciation that abandoned wells represent a potential risk in these historic oil basins. The potential competing proposals for how to address this abandoned well risk are discussed in Part II. In Part III, this paper discusses the post-contamination remedies that would potentially apply if there were a pollution event. For the reasons discussed in Part III, this Article concludes that reliance

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36. *See, e.g.*, INTERSTATE OIL & GAS COMPACT COMM'N, PROTECTING OUR COUNTRY'S RESOURCES: THE STATES' CASE FOR ORPHANED WELL PLUGGING INITIATIVE 5 (2008), http://iogcc.publishpath.com/Websites/iogcc/pdfs/2008-Protecting-Our-Country's-Resources-The-States'-Case.pdf [hereinafter IOGCC, THE STATES' CASE]; INTERSTATE OIL & GAS COMPACT COMM'N, PRODUCE OR PLUG: A STUDY OF IDLE OIL AND GAS WELLS 5 (2000); INTERSTATE OIL & GAS COMPACT COMM'N, AD HOC IDLE WELL COMMITTEE, PRODUCE OR PLUG: THE DILEMMA OVER THE NATION'S IDLE OIL AND GAS WELLS 4 (1996); Keith T. Thomas, Interstate Oil and Gas Compact Comm'n, *Produce or Plug? A Summary of Idle and Orphan Well Statistics and Regulatory Approaches*, SOC'Y PETROLEUM ENG'RS, No. 68695, 2001, at 7.

37. *See, e.g.*, Matthew T. Reagan et al., *Numerical Simulation of the Environmental Impact of Hydraulic Fracturing of Tight/Shale Gas Reservoirs on Near-Surface Groundwater: Background, Base Cases, Shallow Reservoirs, Short-Term Gas, and Water Transport*, 51 WATER RESOURCES RES. 2543 (2015).

38. *See Hydraulic Fracturing*, AM. PETROLEUM INST., http://www.api.org/news-policy-and-issues/hydraulic-fracturing (last visited July 22, 2018) ("Without fracking, there'd be no American energy renaissance . . . ."); *see also* BRADLEY T. EWING ET AL., ECONOMIC IMPACT: PERMIAN BASIN'S OIL & GAS INDUSTRY (2014); News Release, Energy Info. Admin., Hydraulically Fractured Horizontal Wells Account for Most New Oil and Natural Gas Wells (Jan. 30, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34732 ("In 2016, hydraulically fractured horizontal wells accounted for 69% of all oil and natural gas wells drilled in the United States and 83% of the total linear footage drilled.").

solely on after-the-fact remedies is less desirable in comparison to a regulatory framework that reduces the risk of these events occurring in the first place. Finally, in Appendix A, this Article sets forth a survey of the existing regulatory regimes that have been adopted in North America. By considering this question from the perspectives of other competing claims, post-event remedies, and existing regulatory regimes that have been enacted, the authors conclude that the policy proposal set forth in this Article provides an optimum legal and policy framework that regulatory agencies and industry should adopt to mitigate this potential risk.

I. ABANDONED WELLS

Estimates of the number of improperly abandoned wells that exist across this nation are staggering. One study estimates that Pennsylvania alone has 200,000 improperly abandoned wells.[39] In Texas, official records indicate that over 645,000 oil or gas wells have been drilled since 1894.[40] The state has approximately 272,370 active wells and 43,248 injection, disposal, or other service wells currently in operation.[41] Thus, in Texas, there appear to be at least 329,383 wells that are either inactive or abandoned. All oil producing states have instituted programs to identify and plug abandoned and orphaned wells,[42] but those efforts are subject to budgetary and practical constraints.[43] Moreover, today's oil and gas shale development occurs in and around conventional oil fields that have been heavily drilled for almost a century.[44] The intersection of these two realities creates a need for a regula-

39. Scott Detrow, *Perilous Pathways: Behind the Staggering Number of Abandoned Wells in Pennsylvania*, ST. IMPACT PA. (Oct. 10, 2016, 8:05 AM), https://stateimpact.npr.org/pennsylvania/2012/10/10/perilous-pathways-behind-the-staggering-number-of-abandoned-wells-in-pennsylvania/ (noting the dangers of drilling near abandoned wells and the public policy concerns associated with an information gap regarding where those wells sit).

40. TEX. R.R. COMM'N, SELF-EVALUATION REPORT SUBMITTED TO THE SUNSET COMMISSION 65 (2015), https://www.sunset.texas.gov/public/uploads/files/reports/RRC%20Self%20Evaluation%20Report%202015-WEB%20VERSION.pdf.

41. *Id.*

42. *See* IOGCC, THE STATES' CASE, *supra* note 36, at 3, 27-61 (noting that the Interstate Oil and Gas Compact Commission has been studying orphaned wells and the regulations associated with them since 1992 and providing a summary of the various state responses to this systemic issue); *see also* OIL & GAS DIV., TEX. R.R. COMM'N, OIL FIELD CLEANUP PROGRAM ANNUAL REPORT — FISCAL YEAR 2016 (2016), http://www.rrc.state.tx.us/media/37219/ogrc-annual-report-2016.pdf (detailing efforts in Texas).

43. *See* IOGCC, THE STATES' CASE, *supra* note 36, at 6 ("The number of wells waiting to be plugged in individual states at any given time may depend on a variety of factors, such as . . . the availability of state plugging funds . . . .").

44. *See, e.g.*, Press Release, U. S. Geological Survey, USGS Estimates 20 Billion Barrels of Oil in Texas' Wolfcamp Shale Formation (Nov. 15, 2016), https://www.usgs.gov/news/usgs-estimates-20-billion-barrels-oil-texas-wolfcamp-shale-formation; *see also* Rebecca Hersher, *USGS Announces Largest Oil and Gas Deposit Ever Assessed in U.S.*, NPR, (Nov. 16, 2016, 5:40 PM), https://www.npr.org/sections/thetwo-way/2016/11/16/502337471/usgs-announces-its-largest-oil-and-gas-discovery-ever.

tory response that ensures adequate upfront due diligence on the abandoned well risk before hydraulic fracturing operations commence.

A. *Growing State Recognition of Need for Regulation*

A growing number of state regulators recognize that a specific regulatory response is needed to address the risks posed by abandoned wells located near a well that is to be hydraulically fractured.[45] The following statement by Pennsylvania's Department of Environmental Protection frames the issue well:

> When oil- or gas-bearing reservoirs are vertically isolated from shallower, freshwater aquifers serving as sources of drinking water by adequate intervening rock layers, *hydraulic fracturing* can be utilized with negligible risk to waters of the Commonwealth. However, when other wells penetrate the *zone of hydraulic fracturing influence*, they increase risk by serving as potential conduits to the surface and shallow subsurface. Properly plugged or equipped operating wells notably lessen this risk.[46]

On a federal level, the U.S. Environmental Protection Agency has issued recent studies on the impacts of hydraulic fracturing on water sources.[47]

In Appendix A, the authors set forth a survey of the various regulatory responses. The appendix demonstrates that a consensus is growing that a response is needed, but there is no consensus in terms of a specific regulatory response. In the view of the authors, a model regulatory response should provide a transparent process that is scientifically based.

Before addressing this paper's specific regulatory proposal, it is helpful to first consider the industry's proposed response to this concern, and then to consider a competing model regulatory response offered by the Environmental Defense Fund. Analyzing these competing frameworks illuminates the metrics that should be utilized to assess the efficacy of the existing regulatory regimes that are set forth in Appendix A and of the regulatory proposal set forth in this paper.

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45. *See infra* Appendix A (providing a survey of the extant state responses to this systemic risk). For a similar concern in the Canadian context, see BENJAMIN DACHIS ET AL., ALL'S WELL THAT ENDS WELL: ADDRESSING END-OF-LIFE LIABILITIES FOR OIL AND GAS WELLS 5, (C.D. Howe Commentary No. 492, 2017) (noting the environmental and opportunity costs of inactive wells).

46. OFFICE OF OIL & GAS MGMT., DEP'T OF ENVTL. PROT., DOC. NO. 800-0810-001, GUIDELINES FOR IMPLEMENTING AREA OF REVIEW (AOR) REGULATORY REQUIREMENT FOR UNCONVENTIONAL WELLS 1 (2016).

47. *See, e.g.*, OFFICE OF RESEARCH AND DEV., U.S. ENVTL. PROT. AGENCY, EPA-600-R-16-236FA, HYDRAULIC FRACTURING FOR OIL AND GAS: IMPACTS FROM THE HYDRAULIC FRACTURING WATER CYCLE ON DRINKING WATER RESOURCES IN THE UNITED STATES (2016).

B. *Industry Response: American Petroleum Institute Report*

The American Petroleum Institute (API) recognizes the environmental risks associated with hydraulically fracturing a horizontal well near an adjacent well. API explicitly states that prudent operators should proactively identify abandoned wells within the area of fracturing interest before commencing hydraulic fracturing operations:

> Wells that are operating or abandoned (including orphaned wells) that are near current drilling and hydraulic fracturing operations pose potential risk to containment of fracturing and well fluids. . . . Operators should establish an area of investigation (AOI) around each well being drilled and hydraulically fractured to assess and mitigate potential risks.[48]

After making the above general statement that explicitly recognizes the potential environmental risks arising from hydraulic fracturing treatments on wells located close to abandoned wells, the API report goes on to state that the operator should determine the area of fracturing interest, which the API report considers to be the area in which hydraulic fracturing fluids will ultimately extend and be confined.[49] Importantly, once the area of fracturing interest is determined, the API report indicates that the operator should then identify existing well penetrations and non-sealing faults that exist within the area of fracturing interest prior to drilling.[50] The API report notes that identifying each well, its location, and its condition may require consulting a variety of sources.[51] To deal with this problem, the API report sets forth a non-exhaustive list of methods that operators should use to locate wells within an area of fracturing interest that includes the following: (a) company records; (b) records of offset operators; (c) public databases; (d) regulatory agency records; (e) maps; (f) air or satellite photographs; (g) landowner interviews; (h) field reconnaissance; (i) magnetometer surveys to detect hidden metal casing; and (j) satellite radar to detect and map injection pressures in 2D.[52]

For existing wells located within the area of fracturing interest, the API report states that the operator should conduct a risk assessment to evaluate the potential impacts of a proposed well's hydraulic fracturing treatment on other well(s), and this risk assessment should address each of the following questions: (a) what is the location of each well that exists?; (b) where is each well in relation to the well being drilled and fractured?; (c) what is that well's location in regard to the estimated fracture growth?; (d) what is known about the condition of each existing well's

48. AM. PETROLEUM INST., ANSI/API RECOMMENDED PRACTICE 100-1, HYDRAULIC FRACTURING—WELL INTEGRITY AND FRACTURE CONTAINMENT ¶ 4.3.1 (2015), http://www.api.org/~/media/Files/Policy/Exploration/100-1_e1.pdf.

49. *See id.* ¶ 4.3.2.

50. *Id.* ¶ 4.3.2.3.

51. *Id.*

52. *Id.*

construction integrity including whether such wells have been properly plugged?; and (e) are there faults or other geologic heterogeneities potentially intersecting the well being drilled and that will be subjected to hydraulically fracturing treatments?[53] For each identified risk, the API report then states that the operator should put mitigation steps in place to protect against loss of zonal containment.[54] The report then provides that the operator's risk mitigation steps may include any of the following: (a) redesigning the well to avoid the hazard (location, lateral length, etc.); (b) redesigning the completion (perforation cluster location, fracture size, stage avoidance, etc.); (c) intervening in the adjacent well either to confirm or to provide integrity; (d) monitoring the well while performing the drilling or fracturing operations for indications of fracture communication with other wells or a naturally occurring transmissive fault; and finally, (e) not drilling the well.[55]

The final part of the API report risk assessment explicitly asserts that careful consideration should be given to avoid fracture communication between surrounding wellbores, including wellbores of abandoned wells.[56] In this regard, the API report provides that the operator's understanding of the geomechanical properties of a reservoir, and the adjacent zones, is one of the key data requirements for designing, executing, and maintaining zonal isolation.[57] Moreover, the API report points out that the operator must understand the strength, thickness, and other various rock properties, such as Young's modulus and Poisson's ratio, of the confining barrier to determine whether the confining barrier will contain the fracture.[58] The API report then states that the operator should consider data from fracture treatments in the area, along with analysis of pressure data obtained during the actual treatment, in its evaluation of whether the area of fracture interest has a sufficient confining barrier and whether the area of fracturing interest intersects with another well or another naturally transmissive fault.[59] Thus, the above statements by the API report recognize that the operator should engage in significant upfront due diligence to determine the area of fracturing interest and the risks posed by nearby wells.

When it comes to the ongoing monitoring of the impacts from the hydraulic fracturing treatment, however, the API report is less specific. The API report indicates that operators should identify and establish an agreed process for managing

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53. *Id.* ¶ 4.3.3.

54. *Id.* ¶ 4.3.4.

55. *Id.*

56. *Id.* ¶ 4.4.

57. *Id.* ¶ 8.5.1.

58. *Id.*

59. AM. PETROLEUM INST., ANSI/API RECOMMENDED PRACTICE 100-2, MANAGING ENVIRONMENTAL ASPECTS ASSOCIATED WITH EXPLORATION AND PRODUCTION OPERATIONS INCLUDING HYDRAULIC FRACTURING ¶ 8.5.2 (2015), https://www.api.org/~/media/Files/Policy/Exploration/100-2_e1.pdf.

the fracturing operation and for assessing its potential impact on any offset operations (drilling, production, interventions, etc.).[60] The API report does not mandate that baseline water testing be done,[61] but recognizes its benefits in other pronouncements while again stopping short of advocating that it be conducted in all cases.[62] Thus, in this area, the API report leaves much to interpretation and operator judgment.

In terms of engagement with adjacent landowners and offset well operators, the API report stops short of stating that an operator should notify all adjacent landowners and offset well operators before commencing the hydraulic fracturing operation of a nearby well. Instead, the API report makes a general statement that industry participants should "creat[e]. . . an internal network with other stakeholders (e.g., interventions manager, completions manager, new wells delivery manager, etc.)," to efficiently exchange information.[63] It calls for operators to establish relationships with the other regional operators and service companies to efficiently exchange information.[64]

In summary, the API report sets forth upfront precautionary standards of conduct and investigation that a prudent operator should take to mitigate the abandoned well risk. For that reason, this API recommendation is commendable. However, the API report relies almost entirely on the business judgment of the operator in identifying and remediating any potential risk posed by nearby abandoned wells. Moreover, the API report does not envision a significant role on the part of the regulatory agency, nor does it give any specific procedural rights to other affected parties.[65] Thus, although the API report admirably urges the industry participants to address these environmental concerns upfront before engaging in a hydraulic fracturing treatment, it fails to set forth a transparent or objective process and instead relies on the business judgment of each operator.

C. *Environmental Defense Fund's Model Regulatory Framework*

Whereas API largely provides an operator-centric approach to the abandoned well risk, the Environmental Defense Fund, in collaboration with other industry participants, issued a Model Regulatory Framework for Hydraulically Fractured

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60. ANSI/API RECOMMENDED PRACTICE 100-1, HYDRAULIC FRACTURING, *supra* note 48, ¶ 4.4.

61. *See id.* ¶ 4.4. For a more thorough analysis of baseline water sampling, see Keith Hall, *Hydraulic Fracturing and the Baseline Testing of Groundwater*, 48 U. RICH. L. REV. 857 (2014).

62. ANSI/API RECOMMENDED PRACTICE 100-2, MANAGING ENVIRONMENTAL, *supra* note 59, ¶ 8.1.4 (2015).

63. ANSI/API RECOMMENDED PRACTICE 100-1, HYDRAULIC FRACTURING, *supra* note 48, ¶ 4.4(b).

64. *Id.* ¶ 4.4(c).

65. *See generally id.* ¶ 4.3.1.

Hydrocarbon Production Wells (EDF Model Regulatory Framework).[66] The Environmental Defense Fund stated that its goal in developing its EDF Model Regulatory Framework was to assist state governments in implementing a distinct regulatory regime to ensure the integrity of a hydraulically fractured well along with its surrounding fracture network throughout the well's full life-cycle, beginning with the permitting process and ending with its plugging and abandonment.[67]

In terms of specifics, the EDF Model Regulatory Framework recommends, as a precondition for an agency's approval to authorize the drilling of a horizontal well that will be hydraulically fractured, that the operator submit a report that documents the operator's determination of the area of fracturing interest and the investigatory due diligence performed by the operator to determine the possible existence of any abandoned wells. Specifically, the EDF Model Regulatory Frame-Framework states that the operator must submit the following to the regulatory agency prior to any regulatory approval of a hydraulic fracturing treatment:

- i) a plan of a proposed well's location and compliance with existing spacing rules,
- ii) a statement of how the well will be hydraulically fractured that will include the type of base fluid,
- iii) the estimated total volume of hydraulic fracturing fluid and proppant to be used,
- iv) the maximum anticipated pumping pressure,
- v) the anticipated surface treating pressure range for the hydraulic fracturing treatment,
- vi) the calculated estimated fracture length and height anticipated as a result of the hydraulic fracturing treatment,
- vii) the anticipated source or sources for the base fluid,
- viii) a statement describing the anticipated method of handling, recycling or disposal of the flowback and produced water from the well, and
- ix) an analysis by the operator of the intervening zone.[68]

Under the EDF Model Regulatory Framework, the operator also would be required to demonstrate its basis for concluding that all injected hydraulic fracturing fluids would go into the zone(s) to be hydraulically fractured, and that protected water zones would not be contaminated by hydraulic fracturing fluids, proppants, hydrocarbons, or other mobilized contaminants.[69] As part of this evaluation, the

66. *See generally* ENVTL. DEF. FUND, MODEL REGULATORY FRAMEWORK FOR HYDRAULICALLY FRACTURED HYDROCARBON PRODUCTION WELLS (2014), https://www.edf.org/sites/default/files/content/Model_Regulatory_Framework_For_Hydraulically_Fractured_Hydrocarbon_Production_Wells_2014.pdf.

67. *Id.* at 1.

68. *Id.* at 8-10.

69. *Id.* at 30.

operator would provide the basis for its conclusion that the confining layers are sufficient to prevent migration of fluids from the area of fracturing interest to zones containing protected water.[70]

Importantly, the EDF Framework would require the operator to identify all other well bores (including abandoned and orphaned wells), along with natural faults in the area of fracturing interest, and then evaluate the fault's capacity to serve as a potential conduit.[71] The operator's evaluation must set forth a detailed scientific analysis that considers all of these factors and provides the basis for the operator's conclusion that the fluids within the area of fracture interest will be contained.[72] Again, this upfront analysis must be provided to the regulatory agency to obtain approval to commence the operator's hydraulic fracturing treatment under the regulatory regime envisioned by the EDF Model Regulatory Framework.[73]

Although the regulatory regime envisioned by the EDF Model Regulatory Framework provides an opportunity for an upfront fact-based analysis by both the operator and the regulator, the approach creates practical difficulties for regulators because the EDF Model Regulatory Framework leaves the determination for defining the area of fracturing interest in the first instance to the operator.[74] As a result, individual operator judgments could create ambiguity and a potential lack of transparency for how the area of fracturing interest is determined. Moreover, the EDF Model Regulatory Framework places the regulatory agency in a reactive role of assessing the scientific models of each unique operator, which may be a cumbersome process for the regulatory agency. For small operators, the obligation to determine the area of fracturing interest may prove overly burdensome and beyond their capabilities. In addition, the EDF Model Regulatory Framework does not assure public participation by affected parties.[75] Thus, although the EDF Model Regulatory Framework envisions that the operator and the regulatory agency will engage in an upfront dialogue about the risk of abandoned wells before a permit application were to be approved, it leaves considerable discretion in how that process would be worked out in individual permit applications.[76]

II. ANALYSIS OF PRIVATE CAUSES OF ACTION FOR ENVIRONMENTAL CONTAMINATION CLAIMS

If the current proposals to forestall impingement on abandoned wells fall short, do tort remedies and private environmental enforcement actions fill the gov-

70. *Id.*

71. *Id.*

72. *Id.* at 32.

73. *Id.* at 32-33.

74. *Id.* at 32.

75. *See generally* ENVTL. DEF. FUND, *supra* note 66.

76. *See id.* at 31-35.

ernance gap? In addition to the varying state oil and gas regulations that govern the drilling and development of hydraulically fractured wells in areas that may adjoin abandoned sites, tort laws and federal and state environmental regulations arguably could spur well developers to identify and mitigate these types of risks. This path to oversight weaves through a complex web of exclusions, exemptions, and jurisdictional limitations on the application of environmental statutes to oil and gas operations. As a result, the accounting for abandoned wells near hydraulic fracturing operations may turn on the vagaries of location, the types of emitted wastes or pollutants, and the specific kinds of environmental media (such as soil, groundwater, or air) affected by the operation.

Most importantly, a state agency's decision to permit the hydraulic fracturing of a well without requiring an investigation for potential nearby abandoned wells will not insulate the well operator from liability. Generally, receiving an environmental permit from a federal agency would not bar private parties from suing operators who tortiously harm their property interests.[77] The limited protection proffered by permits to tort liability can also apply to state permits. As one Texas court noted, a permit from a state agency is not "a get out of tort free card."[78] As a result, even if a state agency allows an operator to hydraulically fracture a well without first assessing the risks posed by nearby abandoned wells, that agency's approval will not protect the operator against lawsuits under tort law or contract claims. Thus, in assessing the cost-benefit analysis of designing any upfront regulatory regime, a logical question is whether one could simply rely on post-contamination laws in lieu of designing a prophylactic regulatory regime. The below analysis sets forth the potential legal risks associated with well contamination to further support the notion that upfront due diligence is preferable to relying on post-contamination liability and enforcement measures.

A. *Tort and Contract Liability*

In the absence of clear regulatory standards, tort liability will likely play a key role in shaping the expected standards of conduct for hydraulic fracturing near abandoned well sites. For example, well operators who ignore apparent risks from nearby and visible abandoned sites would presumably bear liability for foreseeable damages if they negligently or recklessly stimulate their well without taking reasonable precautions to identify or minimize that foreseeable risk (assuming that failure injures someone to whom the operator owes a duty of care). Tort claims against those operators, however, could vary widely per the types of plaintiffs that were injured by their actions as well as the types of torts that the victims allege.

Most tort claims will face similar challenges. First, many of these claims will arise from injuries caused by releases that occurred in the past because of potential-

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77. *See* Int'l Paper Co. v. Ouellette, 479 U.S. 481 (1987).

78. FPL Farming Ltd. v. Envtl. Processing Sys., L.C., 351 S.W.3d 306, 311 (Tex. 2011).

ly slow migration of contaminants through subsurface strata or groundwater aquifers.[79] If an injured party discovers the injury, a statute of limitations may bar the claim if they had knowledge of the condition or should have undertaken a diligent investigation that could have uncovered the contamination.[80] For permanent nuisances under some state laws, a statute of repose may begin to run upon the occurrence of the release even if the injured party was unaware of the contamination.[81] Second, the performance of multiple hydraulic fracturing operations in the same area as well as the difficulty of fingerprinting chemicals from specific drilling projects may make it difficult for an injured party to prove that a specific operator caused a particular injury.[82] Third, the amount of damages that an injured party may recover could be problematic if the value of the property is far smaller than the cost of remediating the pollution caused by the releases. In the end, every specific tort action will turn heavily on the specific facts, circumstances, and state laws that apply to the incident.

1. Claims by Surface Estate Owners

An errant hydraulic fracturing hit on an abandoned well is most likely to injure the surface owner, who could have both tort and contract claims (if the surface owner has a use agreement with the operator).[83] All major oil producing states im-

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79. Of course, the high pressures of hydraulic fracturing may substantially accelerate the pace of groundwater contaminant migration onto adjacent properties. *See* Yusuke Kuwayama, Sheila Olmstead, & Alan Krupnick, *Water Quality and Quantity Impacts of Hydraulic Fracturing*, 2 CURRENT SUSTAINABLE/RENEWABLE ENERGY REP. 17, 22 (2015).

80. *See, e.g.*, Max Oil Co. v. Range Prod. Co., 681 Fed. App'x 710, 711 (10th Cir. 2017) (trespass and nuisance tort claims for decreases in oil production allegedly caused by nearby hydraulic fracturing barred by Oklahoma's two-year statute of limitations).

81. CTS Corp. v. Waldburger, 134 S. Ct. 2175, 2178-79 (2014).

82. Thomas Merrill & David Schizer, *The Shale Oil and Gas Revolution, Hydraulic Fracturing, and Water Contamination: A Regulatory Strategy*, 98 MINN. L. REV. 145, 235-36 (2013); *see generally* Tarek Saba, *Evaluating Claims of Groundwater Contamination from Hydraulic Fracturing*, OIL & GAS J. (July 1, 2013), https://www.ogj.com/articles/print/volume-111/issue-7/drilling-production/evaluating-claims-of-groundwater-contamination.html (discussing methods and difficulties of fingerprinting particular chemicals and contaminants from hydraulic fracturing in groundwater); Jeffrey C. King et al., *Factual Causation: The Missing Link in Hydraulic Fracture-Groundwater Contamination Litigation*, 22 DUKE ENVTL. L. & POL'Y J. 341, 341-45 (2011); *see generally* Stephen Osborne et al., *Methane Contamination of Drinking Water Accompanying Gas-Well Drilling and Hydraulic Fracturing*, 108 PNAS 8172 (May 17, 2011) (asserting that the difficulties only magnify when the drilling allegedly causes groundwater pollution from natural contaminants that might arise from other sources, such as methane contamination or chloride intrusion).

83. In particular, if the hydraulically fractured well operates within the same surface estate that contains the abandoned well, any discharges from the affected abandoned well will most likely damage the surface owner rather than adjacent surface estate owners or other mineral estate holders. In Texas, a mineral estate owner cannot bring a trespass claim against another producer who drills through the subsurface estate because their subsurface mineral estate did not include a right to exclude transit by other

pose on the operator an implied covenant obligation to conduct operations with reasonable care and due diligence.[84] Courts have extended this implied covenant duty to include the obligation to utilize new technology and to keep up with industry standards of prudence. For example, in *Waseco Chemical Supply Co. v. Bayou State Oil Corp.*, a lessee was held to have breached its implied covenant to administer the leasehold estate when it failed to engage in contemporary prudent practices even though they might not have been envisioned or contemplated at the time the original lease was executed.[85]

Moreover, if a reasonably prudent operator would rework a well more quickly or could better maximize the time value of money return, then the failure to do so can represent a breach of the implied covenant duty to administer the leasehold estate.[86] The lessee cannot shift the blame for negligently producing the leasehold estate off onto its contractors.[87] The heightened due diligence requirements contemplated by the API Report and the EDF Model Regulatory Framework set forth evidence of prudent operator practices,[88] and so a jury might be able to conclude that an operator acted unreasonably by failing to consider these prudent precautions as unreasonable. Thus, as improved knowledge about expected risks and protective procedures becomes more and more known, the operator will be required to conduct its well site activities in accordance with enhanced reasonable precautions that reflect the standard of conduct reasonably expected based on current information.

The usual remedy for a breach of the lessee's implied covenant duty to prudently administer the leasehold estate is an action for damages.[89] Under Texas law,

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mineral estate holders (if the surface estate holder has granted permission). Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39, 53 (Tex. 2017).

84. *See* 5 WILLIAMS & MEYERS, OIL AND GAS LAW § 861.3 (Patrick Martin & Bruce Kramer ed.); OWEN L. ANDERSON ET AL., HEMINGWAY OIL AND GAS LAW AND TAXATION § 8.5(A) (4th Ed. 2004); EUGENE KUNTZ ET AL., 5 KUNTZ OIL AND GAS LAW § 59.1 (Matthew Bender, Rev. Ed.); ERNEST E. SMITH & JACQUELINE WEAVER, 1 TEXAS OIL AND GAS LAW SECTION § 5.4(C)(2).

85. *See, e.g.*, Waseco Chem. & Supply Co. v. Bayou State Oil Corp., 371 So. 2d 305 (La. Ct. App. 1979); *see also* Util. Prod. Corp. v. Util. Prod. Corp., 72 F.2d 655, 659 (10th Cir. 1934) (court stated that lessee had duty to use improved techniques to recover residue gas as technology enhancements became available); Wadkins v. Wilson Oil Co., 6 So. 2d 720, 724 (La. 1942) (failure to drill and acidize wells in a chalk formation represented a breach of the implied covenants under the lease even thought this process was unknown when the lease was executed); Rhoads Drilling Co. v. Allred, 70 S.W.2d 576, 585 (Tex. Comm'n App. 1935) ("A lessee's obligation in the performance of implied covenants as to development, operation, equipping, and marketing are measured by the same rule, reasonable diligence, or what an ordinarily prudent operator would do.").

86. *See, e.g.*, Temple v. Cont'l Oil Co., 320 P.2d 1039, 1055-56 (Kan. 1948) (holding time as an element of diligence).

87. *See, e.g.*, Empire Oil & Refining Co. v. Hoyt, 112 F.2d 356, 362 (6th Cir. 1940); Flanigan v. Stern, 265, S.W. 324, 326 (Ky. 1924).

88. *See supra* Parts II.B. to II.C.

89. W.T. Waggoner Estate v. Sigler Oil Co., 19 S.W.2d 27, 29 (Tex. 1929).

each landowner owns the oil and gas that underlies their particular land.[90] The drilling and production activities on one tract of land can create pollution and environmental contamination to other tracts or to surface owners. The Rule of Capture arose early as a non-liability rule that protects lessees from tort claims by adjacent tract owners,[91] but this non-liability rule only extends to production operations that are lawful and reasonably conducted.[92] Thus, if an operator's hydraulic fracturing impacts an abandoned well and consequently illegally or unreasonably pollutes or damages neighboring tracts, owners of mineral interests in the neighboring tracts have standing to bring a cause of action against that operator. The neighbor's claim would simply allege that the operator's pursuit of hydraulic fracturing operations without adequate precautions constituted an improper and unreasonable production practice that harmed their subsurface property rights. The Rule of Capture, which normally protects operators from claims of improper drainage from adjoining properties, would not protect the operator from claims of negligence[93] or trespass.[94]

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90. Stephens Cty. v. Mid-Kansas Oil & Gas Co., 254 S.W. 290, 291 (Tex. 1923).

91. *See* Riley v. Riley, 972 S.W.2d 149, 155 (Tex. App. 1998); *see also* Ryan Consol. Petroleum Corp. v. Pickens, 285 S.W.2d 201, 208 (Tex. 1955).

92. ERNEST E. SMITH AND JACQUELINE L. WEAVER, TEXAS LAW OF OIL AND GAS, § 1.1[B][1] at 3 (2018).

93. In *Eliff v. Texon Drilling Co.*, 210 S.W.2d 558 (Tex. 1948), the Texas Supreme Court made clear that the nonliability protection afforded by the Rule of Capture for drainage of neighboring tracts did not protect an operator who drained neighboring tracts when such drainage was the result of negligent and wasteful production. In *Elliff*, the negligent drilling practices of the lessee caused a blow-out of a well which in turn caused drainage from neighboring tracts. *Id*. Furthermore, the operator's blow-out in *Elliff* resulted in all of the production being burned into the atmosphere, and in this context the Texas Supreme Court held in that case that the burning of all production represented negligence on the part of the operator, and as such the operator was liable to the landowner of the adjacent tract for any damage resulting from the drainage of the adjacent tracts arising from the negligent production. *See* Texon Drilling Co. v. Elliff, 216 S.W.2d 824 (Tex. Civ. App. 1948).

94. The Texas Supreme Court's support for this potential cause of action is bolstered by the reasoning that the Court employed in *Coastal Oil & Gas Corp. v. Garza Energy Trust*, 268 S.W.3d 1 (Tex. 2008). In this case, Coastal (the lessee) fractured the Vicks T formation after completing a validly spaced well. *Id.* at 13. The jury found that the hydraulically induced fractures crossed lease lines and thus extended onto neighboring tracts of adjacent landowners. *Id.* at 8. The Texas Supreme Court, in a divided opinion, held that the royalty owner of the neighboring tract had a nonpossessory interest in the neighboring tract and thus could only bring a cause of action if the royalty owner showed that an actionable trespass had occurred. *Id.* at 11. The Texas Supreme Court then went on to state that an actionable trespass did not exist in the facts of *Coastal Oil & Gas Corp. v. Garza Energy Trust* because the direct consequence of the hydraulic fracturing operation was to subject the neighboring tract to drainage that was legally protected from liability by reason of the Rule of Capture. *Id.* at 12-13. However, in the course of its opinion, the Texas Supreme Court stated that the possibility for liability does exist in situations where the lessee's drainage was the result of conduct that was otherwise "illegal, malicious, reckless, or intended to harm another without commercial justification"; in those situations, the Texas Supreme Court stated that the Rule of Capture would not protect the lessee from the drainage claims of neighboring tract owners. *Id.* at 17.

If an operator's activities substantially interfere with the use and enjoyment of another's land, the affected neighboring landowner may have a claim based on nuisance.[95] Although aesthetic changes to land generally do not rise to the level of an actionable nuisance,[96] an operator's actions that cause physical harm to property or to a person who uses their own property is actionable.[97] A permit granted by a state regulatory agency to perform the activity that creates the harm to another landowner does not immunize the operator from claims arising in nuisance.[98] If the operator's actions injure someone who owns a separate tract, then that separate owner can generally assert a nuisance claim because her separate tract does not have to reasonably accommodate the development activities of mineral interest owners of other tracts.[99]

Conducting hydraulic fracturing treatments in a manner that does not safeguard against the migration of fracturing fluids outside of the area of fracturing interest can harm adjacent surface owners who live in and around the area where the pollution occurs. Surface owners who can claim that they have experienced an environmental or physical harm as a result of the hydraulic fracturing operations of an operator would be able to make a claim in nuisance.[100]

However, when the surface owner is the surface owner of the same tract where the operator has the right to conduct oil and gas operations, the case law has set forth the general rule that the mineral estate is the dominant estate.[101] The mineral estate owner is considered to have an implied easement to use the surface and subsurface in any way reasonably necessary for exploring, drilling, producing, transporting, and marketing oil and gas.[102] The operator, as the working interest owner of the mineral estate, is entitled to use such portion of the surface estate as is reasonably necessary to develop the mineral estate.[103] Nevertheless, even though the mineral estate is dominant, the mineral estate owner's rights are not absolute. In

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95. Holubec v. Brandenberger, 111 S.W.3d 32, 37 (Tex. 2003).

96. Rankin v. FPL Energy LLC, 266 S.W.3d 506, 509 n.3 (Tex. App. 2008).

97. Walton v. Phillips Petroleum Co., 65 S.W.3d 262, 270 (Tex. App. 2001), *abrogated by In re* Estate of Swanson, 130 S.W.3d 144 (Tex. App. 2003).

98. FPL Farming Ltd. v. Envtl. Processing Sys., L.C., 351 S.W.3d 306, 310 (Tex. 2011).

99. *See* Michael Goldman, *A Survey of Typical Claims and Key Defenses Asserted in Recent Hydraulic Fracturing Litigation*, 37 REP. OIL, GAS & ENERGY RESOURCES L. SEC. ST. BAR OF TEX. 43, 57 (2013).

100. *See* Heinkel-Wolfe v. Williams Prod. Co., No. 2010-40355-362 (362nd Dist. Ct., Denton Cty., Tex. Filed Nov. 3, 2010) (claiming, among other things, that the operator's activities created air pollution that created respiratory ailments, headaches, and resulted in the plaintiff's difficulty in breathing); *see also* Vestal v. Gulf Oil Corp., 235 S.W.2d 440, 441-42 (Tex. 1951).

101. *See* Vest v. Exxon Corp., 752 F.2d 959, 961 (5th Cir. 1985); Stradley v. Magnolia Petroleum Co., 155 S.W.2d 649, 652 (Tex. Civ. App. 1941).

102. *See* ERNEST E. SMITH & JACQUELINE L. WEAVER, TEXAS LAW OF OIL AND GAS, § 2.1[B][1], at 2-14 (2013).

103. *Id.* at 2-15.

this regard, the operator must act in a non-negligent manner and must use the surface estate reasonably.[104] Furthermore, the mineral interest owner must reasonably accommodate any prior surface use.[105] Consequently, if the surface owner can demonstrate that a reasonable and prudent operator would not have engaged in hydraulic fracturing operations without ensuring that such operations would not create a migration of fracturing fluids outside of the area of interest and that to do so represented an unreasonable well site practice considering all the facts and circumstances, then the surface estate owner can bring claims based on nuisance against the operator who engages in hydraulic fracturing operations in this manner.

Operators may seek to control their liability to surface estate owners through a surface use agreement that explicitly addressed the obligation to account for hydraulic fracturing effects on abandoned wells or historical operations. Even though lessees under Texas common law may substantially interfere with the surface owner's use and enjoyment of the surface estate as long as the interference is reasonably necessary to develop the mineral estate,[106] to avoid controversy operators nevertheless will often enter into surface use agreements that specify the activities that will be performed on the surface and a methodology for compensating the surface owner for damages caused by such use.[107] Courts have generally upheld the validity of these agreements to the end that surface owners can be considered to have contractually relinquished their claims to object to an unreasonable or excessive use of the surface estate.[108] Thus, if the surface owner is harmed by hydraulic fracturing operations and has signed a surface use agreement, the terms of that particular agreement would need to be carefully considered to determine whether the surface owner has relinquished any of her rights to bring a suit in nuisance.

2. Tort Claims by Other Injured Parties

While surface owners will likely resort to contract actions and property claims to protect their interests against contamination from abandoned wells affected by nearby hydraulic fracturing, other injured persons will likely turn to tort lawsuits. As noted above, the issuance of a permit or other regulatory approval by a state agency will not shield an operator from injury claims under tort, including actions

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104. Texaco, Inc. v. Faris, 413 S.W.2d 147, 149 (Tex. Civ. App. 1967); Brown v. Lundell, 344 S.W.2d 863, 866 (Tex. 1961) (stating that the lessee has been granted "only so much of [the surface owner's] land as will be reasonably necessary to effectuate the purpose of the lease, and to be used in a non-negligent manner").

105. *See* Getty Oil Co. v. Jones, 470 S.W.2d 618, 622-23 (Tex. 1971).

106. *See* Sun Oil Co. v. Whitaker, 483 S.W.2d 808, 812 (Tex. 1972).

107. ERNEST E. SMITH & JACQUELINE L. WEAVER, TEXAS LAW OF OIL AND GAS, § 6.7, at 6-32 (2013) (so stating).

108. *See* Prairie Producing Co. v. Martens, 705 S.W.2d 257, 259-60 (Tex. App. 1986); Union Producing Co. v. Allen, 297 S.W.2d 867 (Tex. Civ. App. 1957).

by injured third parties.[109] As a result, operators who create environmental damages through hydraulic fracturing near abandoned wells might face tort actions from adjoining landowners, individuals who suffer personal injuries from the contamination, or owners of affected non-mineral natural resources (e.g., surface or ground water).[110]

The types of tort actions that could theoretically arise from hydraulic hits on abandoned wells will fall into familiar forms: claims for nuisance, negligence, negligence per se, trespass, and strict liability.[111] Less frequently, plaintiffs may also allege unjust enrichment, tortious interference with business contractual relationships, and intentional infliction of emotion distress.[112] Many of these tort theories have already surfaced in challenges to the fracturing operations themselves,[113] so their extension to abandoned well fracturing hits seems obvious and highly likely.

3. Nuisance

Nuisance tort claims are well-suited for the types of injuries likely to be claimed from abandoned well fracturing hits. Because they only need to show that the defendant's fracturing operations unreasonably interfered with a property owner's enjoyment of his or her property, a nuisance action sidesteps the need to prove that the defendant acted negligently.[114] The infliction of property damage or indi-

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109. *See supra* notes 93 to 94.

110. The possibility of tort claims by owners of mineral estate rights in adjacent properties raises additional unique issues. In particular, to the extent that an operator's hydraulic fracturing results in damages from abandoned sites located on adjacent lands, the mineral estate owner's potential tort claims for damages may arguably be inhibited by the Rule of Capture. The Rule, however, limits liability for loss of recovery of minerals due to draining of nonpossessory interest assets. As a result, the Rule will not apply to damages unrelated to draining of the shared mineral estate asset. It is also unlikely that an adjacent mineral estate owner could claim that physical intrusion into the subsurface violated his or her ownership rights because a mineral estate does bestow exclusive access rights against activities unrelated to mineral extraction. Lightning Oil Co. v. Anadarko E&P Onshore, LLC, 520 S.W.3d 39, 47 (Tex. 2017) (no trespass when horizontally drilled line traveled through subsurface estate to adjacent property without taking any minerals).

111. *See* Leonard Rubin, Note, *Frack to the Future: Considering a Strict Liability Standard for Hydraulic Fracturing Activities*, 3 GEO. WASH. J. ENERGY & ENVTL. L. 117, 123-27 (2012) (considering trespass, nuisance, negligence, and strict liability tort theories to hydraulic fracturing).

112. Given their rarity compared with negligence, nuisance, trespass, and strict liability claims for oilfield pollution, this article will not examine them further. For a prescient assessment of the strengths and weaknesses of these particular tort theories in oilfield contamination litigation, see W. Keffer, *Drilling for Damages: Common Law Relief in Oilfield Pollution Cases*, 47 SMU L. REV. 523, 530-32 (1994).

113. Merrill & Schizer, *supra* note 82, at 197, 259-62; Rubin, *supra* note 111; Hannah Wiseman, *Untested Waters: The Rise of Hydraulic Fracturing in Oil and Gas Production and the Need to Revisit Regulation*, 20 FORDHAM ENVTL. L. REV. 146, 146-56 (2009) (outlining various tort challenges raised to hydraulic fracturing operations in Texas, Kansas, Pennsylvania, and Utah).

114. Manchester Terminal Corp. v. Texas TX TX Marine Transp., Inc., 781 S.W.2d 646, 651 (Tex. App. 1989).

vidual personal injury due to environmental contamination or injury, by themselves, can support a claim of private nuisance in most cases.[115]

While relieved of the need to demonstrate negligence, the injured parties alleging nuisance must still show that the fracturing operations near the abandoned wells caused a material or substantial injury that a person of ordinary health and sensibility in that general location would also have similarly suffered.[116] In general, this obligation translates into an examination of the way that the fracturing was conducted because the mere operation of an oilfield itself would not typically constitute a nuisance.[117] This investigation will weigh whether such fracturing is common in the region, and courts will be more inclined to find that common activities do not create a nuisance.[118]

Beyond more amenable burdens of proof, nuisance claims also offer a broader array of potential remedies to successful claimants. In particular, courts have traditionally awarded relief in nuisance actions through either the cost of abatement or, alternatively, ordering abatement of the nuisance itself.[119] While historically the traditional rule limits successful plaintiffs to the monetary value of the diminution in value of their damaged property,[120] the costs of abatement may dwarf the value of the underlying property itself. The courts have shown a growing willingness to award abatement costs even in excess of the property's value, although some states have taken steps to limit the amount of such awards or have passed statutes that place such awards in registries with the court to assure that they support remediation of the property.[121] Nuisance actions also allow the award of punitive damages,

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115. *See* CREATIVE COMMON LAW STRATEGIES FOR PROTECTING THE ENVIRONMENT 18-26 (Clifford Rechtschaffen & Denise Antolini eds., 2007) (reviewing ubiquity of nuisance claims arising from environmental injuries under U.S. common law).

116. *See* Vestal v. Gulf Oil Corp., 149 Tex. 487, 235 S.W.2d 440 (1951).

117. State courts have long held that lawfully conducted oil and gas well drilling and production operations are not nuisances *per se*. *See* Donn Bennett, *Damages to the Land Owner Following the Oil and Gas Lease*, 13 S.D. L. REV. 29, 41 n.45 (1968); Harry Lambert, *Surface Rights of the Oil and Gas Lessee*, 11 OKLA. L. REV. 373, 382 (1958); Leon Green, *Hazardous Oil and Gas Operations: Tort Liability*, 33 TEX. L. REV. 574, 585 (1955).

118. *See* Richard Epstein, *The Path to* The T.J. Hooper*: The Theory and History of Custom in the Law of Tort*, 21 J. LEGAL STUD. 1, 36-38 (1992). A similar factor would underlie attempts to categorize hydraulic fracturing operations as abnormally dangerous and subject to strict liability. RESTATEMENT (SECOND) OF TORTS § 520(d) (1979) (consideration of whether activity allegedly causing hazard is "a matter of common usage"); RESTATEMENT (THIRD) OF TORTS: LIABILITY FOR PHYSICAL AND EMOTIONAL HARM § 20(b)(2) (activity subjected to strict liability must not be "one of common usage").

119. William Keffer, *Drilling for Damages: Common Law Relief in Oilfield Pollution Cases*, 47 SMU L. REV. 523, 526 (1994).

120. *Id.*

121. *See* Corbello v. Iowa Prod. Co., 850 So. 2d 686, 695 (La. 2003) (allowing restitution damages in excess of the value of affected property). The Louisiana legislature overruled *Corbello* by requiring that payments for remediation costs must be lodged with the court and dedicated to the cleanup of the property. LA. STAT. ANN. § 30:29(D)(1) (2017).

although tort reform statutes in several states can significantly limit recoveries unless plaintiffs prove malice, intentional tort, fraud, or reckless conduct.[122]

In addition to private nuisance claims for interference with their own property, injured parties may also be able to bring public nuisance claims for abandoned well fracturing hits. To do so, they would need to demonstrate that the injury created by the well hit affected a right held by the public in general, and that the plaintiffs had also incurred a special injury distinct from the public at large.[123] Frequently injuries to such publicly held interests involve damage to natural resources that can also allow statutory actions to recover compensation for natural resource damages.[124] The presence of a statutory natural resource damage remedy, however, does not preclude the ability of plaintiffs to also seek common law public nuisance tort compensation.[125] In addition, public nuisance tort actions do not trigger the time limitations imposed by statutes of limitation for tort actions generally.[126]

4. Negligence (and Negligence Per Se)

To prove that an operator has negligently injured them through hydraulically fracturing a well near abandoned wells, the plaintiffs would need to show that the operator owed them a duty of care that the operator's actions had violated.[127] That breach in turn would have had to proximately cause the plaintiffs' injuries.[128] In this context, the plaintiffs would likely allege that the defendants owed them a duty to conduct their operations in a way that did not injure or pollute the plaintiffs' property.

The key question is what sets the standard of care for assessing the risks posed by proposed hydraulic fracturing operations potentially located near abandoned wells. In general, the duty of care for oilfield operations is not perfection; most oil and gas production technologies will inevitably result in some degree of spillage or leaks.[129] As a result, the duty of care typically only requires that the operator con-

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122. *See* TEX. CIV. PRAC. & REM. CODE ANN. § 41.007-.008 (West 2017); COLO. REV. STAT. § 13-21-102(1)(a) (2017); Majors v. Good, 832 P.2d 420, 422 (Okla. 1992).

123. *See* Rebecca Faye Eschen, *A Fracking Nuisance: How States Can Compel Their Neighbors to Regulate Hydraulic Fracturing with Judicial Equitable Relief*, 30 GEO. INT'L ENVTL. L. REV. 149, 161-63 (2017).

124. *See, e.g.*, 42 U.S.C. § 9607(a)(4)(C) (2012) (allowing natural resource damage recovery actions under the Comprehensive Environmental Response, Compensation & Liability Act of 1980).

125. *See supra* note 93; 42 U.S.C. § 9652(d) (2012) (preserving state laws and liabilities for releases of hazardous substances or other pollutants and contaminants from CERCLA preemption).

126. OKLA. STAT. tit. 50, § 1 (2017); *see* City of Corsicana v. King, 3 S.W.2d 857, 861 (Tex. Civ. App. 2018).

127. Christopher Kulander, *Common Law Aspects of Shale Oil and Gas Development*, 49 IDAHO L. REV. 367, 375 (2013).

128. *Id.*

129. Mike Soraghan, *U.S. Well Sites in 2012 Discharged More Oil than Valdez*, E&E NEWS (July 8, 2013), https://www.eenews.net/stories/1059983941/print.

duct the drilling and recovery in a way that does not cause pollution unnecessarily or inexcusably.[130] This standard, however, requires more than mere compliance with regulatory standards or local industry practices. Simple satisfaction of regulatory standards does not automatically assure that the underlying conduct nonetheless occurred negligently given the operator's knowledge and specific circumstances of the actual operation itself.[131] The standard of care may also evolve over time,[132] which could create difficult questions about the relevant standard when a release involves an abandoned well that was closed in accordance with standards that were in effect decades in the past.

The development of industry standards – either as embodied in the suggested API protocol for assessing hydraulic fracturing sites for potential abandoned wells, or the proposed EDF standards – can supply an expected baseline of conduct that can evolve into a de facto duty of care. If states or federal agencies ultimately adopt formal regulatory requirements for assessment of risks posed by hydraulic fracturing near potentially abandoned wells, violation of those standards may in turn also subject the operators to liability under theories of negligence per se.[133] Under this approach, a defendant may face liability if its conduct violated an applicable statute, regulation, or ordinance, and that violation proximately caused the plaintiff's injury (but only if the plaintiff falls within the class of persons that the statute or rule aims to protect).[134] Once the plaintiff meets this burden of proof, the burden of proof then shifts to the defendant to prove that it had a valid excuse for its violation.[135] To the extent that a statute, law, or regulation generally bars the creation of pollution or discharges to waters without a permit, the negligence per se doctrine can offer an attractive platform for plaintiffs to show that hydraulic fracturing operations affecting abandoned wells occurred negligently simply by pointing to an alleged regulatory violation.

5. Trespass

If a hydraulic fracturing hit on an abandoned well introduces pollutants onto a surface owner's property or adjoining land owned by another, the operator will likely also face an action for trespass. This theory would only require proof that the operator had acted in a fashion that led to the invasion of the owner's interest in

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130. Rubin, *supra* note 111, at 124; Pioneer Nat. Res. USA, Inc. v. W.L. Ranch, Inc., 127 S.W.3d 900, 907 (Tex. App. 2004); *see also* Keffer, *supra* note 112, at 527.

131. M. Geistfeld, *Tort Law in the Age of Statutes*, 99 IOWA L. REV. 957 (2014); RESTATEMENT (THIRD) OF TORTS: LIABILITY FOR PHYSICAL AND EMOTIONAL HARM § 14.

132. Epstein, *supra* note 118, at 11-16.

133. RESTATEMENT (THIRD) OF TORTS § 14.

134. *Id.*

135. *Id.* § 14 cmt. c; *id.* § 15 (requiring defendant to prove excuse for conduct that violated regulatory standard).

exclusive possession of their property.[136] While this claim offers the prospect of injunctive relief, actual damages, and punitive damages, it still requires the plaintiff to show that the defendant acted intentionally.[137]

Trespass claims for releases related to fracturing hits on abandoned wells could raise difficult questions about the extent and nature of the property interests affected by the incursion. For example, the application of trespass to underground incursions caused by migration of injected fluids has led the Texas Supreme Court to issue conflicting and unclear rulings.[138] The extent of a mineral estate holder's authorization to operate on the subservient surface estate may also turn on the extent of the rights granted by a surface use agreement and authorization to allow disposal operations.[139] Notably, trespass would likely not apply to arguable incursions caused by vibrations, emissions, smoke, or non-particulate discharges.[140]

6. Strict Liability

If an operator engages in extraordinarily hazardous activities that cause an injury to another person, strict liability doctrine would hold them responsible for damages even if that operator had taken every action possible to avoid the injury. Strict liability, simply put, views the level of care used by the defendant (or even the legality of the defendant's action) as irrelevant.[141] While persons injured by hydraulic fracturing operations improperly close abandoned wells will undoubtedly seek to hold operators strictly liable, the plaintiffs would first have to demonstrate that such oilfield operations are abnormally dangerous or ultra-hazardous.[142] Most jurisdictions, including Oklahoma and Texas, have not viewed traditional oilfield operations as extraordinarily dangerous or an "unnatural" use of land that would

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136. Hillary Goldberg, Melanie Williams, & Deborah Cours, *It's a Nuisance: The Future of Fracking Litigation in the Wake of* Parr v. Aruba Petroleum, Inc., 33 VA. ENVTL. L.J. 1, 8-9 (2015); Kulander, *supra* note 127, at 374; Merrill & Schizer, *supra* note 82, at 261 n.407; Rubin, *supra* note 111, at 123-25.

137. Goldman, *supra* note 99, at 312-13.

138. For example, compare the Texas Supreme Court's approval of waterflooding for oil production as a permissible incursion of property rights, Texas R.R. Comm'n v. Manziel, 361 S.W.2d 560, 567-69 (Tex. 1962), with the limits placed on incursion by injected wastewaters for disposal purposes, FPL Farming Ltd. v. Envtl. Processing Sys., L.C., 351 S.W.3d 306, 314-15 (Tex. 2011). *See also* Alia Heintz, *What's the Harm in a Subsurface Trespass?*, 51 TULSA L. REV. 777, 788-93, 800 (2015) (recounting recent Texas Supreme Court cases on subsurface trespass, author concludes "Texas precedent appears to be in conflict").

139. SHANNON FARRELL ET AL., PETROLEUM PRODUCTION ON AGRICULTURAL LANDS IN TEXAS: MANAGING RISKS AND OPPORTUNITIES §§ 2.4.2-2.5 (2016), https://agrilifeextension.tamu.edu/wp-content/uploads/2016/03/Texas-Oil-Gas-Leasing-Handbook-web.pdf (discussing surface use agreement operations and standard terms).

140. Denise Antolini & Clifford Rechtschaffen, *Common Law Remedies: A Refresher*, 38 ENVTL. L. REP. NEWS & ANALYSIS 10114, 10115 (2008).

141. Rubin, *supra* note 111, at 125.

142. *Id.* at 125-27.

trigger strict liability.[143] Similar attempts have not yet yielded a judgment that classifies hydraulic fracturing as ultra-hazardous activity.[144] To the extent the hydraulic fracturing technologies evolve beyond traditional oilfield operations and use unfamiliar and inherently risky techniques, however, some states may allow lawsuits to apply strict liability doctrines to oilfield pollution from such wells.[145]

B. *Private Actions Under Federal and State Environmental Statutes and Regulations*

In addition to tort actions, parties injured by contamination resulting from hydraulic fracturing near abandoned wells could potentially seek relief under federal and state environmental statutes and regulations. Most environmental statutes include tools for citizens and injured parties to seek enforcement of environmental standards or compel remedial action.[146] The scope of relief offered by these actions can be inconsistent and unpredictable because of substantive exemptions for oilfield operations and petroleum processing and procedural limitations on the use of citizen suits and enforcement actions.

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143. RESTATEMENT (SECOND) OF TORTS § 520(f) factor f, cmt. k (1977) (noting that economic value of oil and gas production in Texas and Oklahoma outweighed its dangerous attributes). While the American Law Institute withdrew its support for an economic value element for strict liability, its observations about the general acceptance of oil and gas activities remain unaffected. RESTATEMENT (THIRD) OF TORTS: LIABILITY FOR PHYSICAL AND EMOTIONAL HARM § 20 cmt. h (noting acceptance of gasoline storage and refining operations in appropriate geographic locations). *See also* Joe Schremmer, *Avoidable "Fraccident": An Argument Against Strict Liability for Hydraulic Fracturing*, 60 KAN. L. REV. 1215, 1239 (2012) ("Courts nationwide have held that the operation of oil and gas wells in oil and gas fields is not abnormally dangerous.").

144. Blake Watson, *Fracking and Cracking: Strict Liability for Earthquake Damage Due to Wastewater Injection and Hydraulic Fracturing*, 11 TEX. J. OIL, GAS & ENERGY L. 1, 2 (2016) ("In no case to date, however, has a court held that either fracking or the injection of fracking wastes is an abnormally dangerous activity.").

145. Kansas has expressly adopted strict liability doctrine as a tool to control pollution, although it has declined to apply the doctrine in specific cases involving oil refining and a natural gas drilling operation. Anderson v. Farmland Indus., 136 F. Supp. 2d 1192, 1198-1201 (D. Kan. 2001); Williams v. Amoco Prod. Co., 734 P.2d 1113, 1123 (Kan. 1987). A district court in Pennsylvania recently ruled that hydraulic fracturing activities are not abnormally dangerous and do not require application of strict liability, Ely v. Cabot Oil & Gas Corp., 38 F. Supp. 3d 518 (M.D. Pa. 2014), but litigation over the issue will likely continue in other ongoing actions; Hannah Coleman, *Balancing the Need for Energy and Clean Water: The Case for Applying Strict Liability in Hydraulic Fracturing Suits*, 39 B.C. ENVTL. AFFAIRS L. REV. 131, 154-59 (2012) (arguing for application of strict liability to hydraulic fracturing operations within Pennsylvania).

146. Frank Cross, *Rethinking Environmental Citizen Suits*, 8 TEMP. ENVTL. L. & TECH. J. 55, 55-58 (1989); Daniel Dunn, *Environmental Citizen Suits Against Natural Resource Companies*, 17 NAT. RESOURCES & ENV'T 161, 161-62 (2003); James May, *The Availability of State Citizen Suits*, 18 NAT. RESOURCES & ENV'T 53, 53-55 (2004).

1. Solid and Hazardous Wastes

Federal and state laws impose management and disposal requirements for solid and hazardous wastes under the Resource Conservation and Recovery Act (RCRA)[147] and its state analogs (e.g., the Texas Solid Waste Disposal Act).[148] These statutes typically impose comprehensive regulatory standards for handling or disposing wastes that display hazardous characteristics or are classified as hazardous wastes by the United States Environmental Protection Agency (EPA).[149] This framework, however, also contains a large exemption: it expressly does not apply to wastes created by exploration and production (E&P) activities for oil and gas.[150] This exemption includes the fluids, discarded solid wastes, cuttings, chemicals, and flowback materials from oil and gas operations.[151] The exemption indisputably applies to hydraulic fracturing operations in pursuit of oil and gas deposits.[152] As a result, RCRA's sweeping hazardous waste management regulatory framework does not apply to E&P wastes in almost all circumstances.

RCRA's E&P exclusion, however, does not swallow every potential regulatory standard for wastes generated by fracturing activities near abandoned wells. In particular, the E&P exclusion only bars the classification of E&P wastes as hazardous.[153] As a result, fracturing materials remain subject to regulation as non-hazardous solid wastes.[154] These standards tend to be far less onerous than hazardous waste regulations (at least on the federal level),[155] but they provide a regulatory predicate to impose additional standards on special non-hazardous solid wastes (such as coal ash or certain types of combustion residue). While EPA has not promulgated such standards, it retains the statutory authority to impose such regulatory obligations in the future.[156] To the extent that hydraulic fracturing operations also generate corollary wastes not directly tied to E&P activities (for exam-

147. 42 U.S.C. §§ 6901-6986 (2012).

148. TEX. HEALTH & SAFETY CODE ANN. § 361.001-.992 (West 2017).

149. *See, e.g.*, 42 U.S.C. §§ 6921-6939 (2012) (comprehensive requirements for hazardous waste identification and handling, including prohibitions on land disposal and permitting requirements for hazardous waste treatment, storage, and disposal facilities).

150. 42 U.S.C. § 6921(b)(2)(A) (2012) (excluding drilling fluids, produced water, and other wastes associated with the exploration, development, or production of crude oil or natural gas from regulation as hazardous wastes until EPA concludes a study and recommends the appropriate level of regulation); 40 C.F.R. § 261.4(b)(5) (2017) (EPA regulation implementing exclusion on a permanent basis).

151. Michael Burger, *The (Re)Federalization of Fracking Regulation*, 2013 MICH. ST. L. REV. 1483, 1486, 1496 (2013).

152. *Id.*

153. 40 C.F.R. § 261.4(b) (2017).

154. Jeffrey Gaba, *Flowback: Federal Regulation of Wastewater from Hydraulic Fracturing*, 39 COLUM. J. ENVTL. L. 251, 274-75 (2014).

155. *See id.* at 277-81 (discussing consequences of listing produced waters from hydraulic fracturing sites as "hazardous," rather than "solid," wastes).

156. *Id.* at 281.

ple, contamination related to sand management or water processing), RCRA hazardous waste standards may apply to those discarded materials if they qualify as hazardous.[157]

RCRA also allows EPA to delegate implementation of hazardous waste program requirements to states that request the authority,[158] and those states can regulate oil and gas E&P wastes under their own state waste statutes. For example, Texas has constructed its own set of regulatory standards[159] for management of E&P waste exempt under RCRA by using the Texas Solid Waste Disposal Act and the Texas Health & Safety Act.[160] These standards delegate authority to regulate exempt E&P wastes to the Texas Railroad Commission rather than the Texas Commission on Environmental Quality.[161] The Texas Railroad Commission has specified management standards for E&P wastes that require protection of water resources and the environment.[162] These regulations, however, tend to be far less stringent than federal requirements for treatment, storage, and disposal of hazardous wastes.[163]

Because E&P wastes from hydraulic fracturing remain subject to regulation as solid wastes under RCRA,[164] EPA retains emergency authorities to respond to past or present handling or disposal of E&P solid wastes that pose an imminent and substantial endangerment to health or the environment.[165] Private parties can bring similar abatement actions through citizen suits under Section 7002 of RCRA against any person whose past or present creation, handling, or disposal of solid waste has created an imminent and substantial endangerment.[166] A private citizen suit can offer the opportunity for an injured party to seek injunctive relief to compel an operator to investigate and respond to an imminent and substantial endangerment.[167] The power of such a suit, however, is tempered by its inability to re-

157. *Id.* at 273-74 (Other wastes not uniquely associated with exploration and production sites using hydraulic fracturing fall within "non-excluded wastes" set aside from EPA's regulatory exclusion.).

158. 42 U.S.C. § 6926(b) (2012).

159. 16 TEX. ADMIN. CODE § 3.1(b), (d) (2017).

160. TEX. NAT. RES. CODE ANN. § 91.101 (West 2017).

161. TEX. HEALTH & SAFETY CODE ANN. § 361.025 (West 2017) (exempting activities associated with oil and gas exploration, development, and production from regulation by TCEQ).

162. 16 TEX. ADMIN. CODE § 3.8, .22, .91 (2017).

163. *See* TEX. R.R. COMM'N, SUNSET ADVISORY COMMISSION REPORT 35-39 (2016).

164. Gaba, *supra* note 154, at 275.

165. 42 U.S.C. § 6973 (2012).

166. 42 U.S.C. § 6972(a)(1)(B) (2012).

167. *See, e.g.*, Interfaith Cmty. Org. v. Honeywell Inc., 399 F.3d 248 (3rd Cir. 2005) (defendant ordered to abate the endangerment by removing contamination); Tanglewood v. Charles-Thomas, Inc., 849 F.2d 1568 (5th Cir. 1988) (remedy can include civil penalties, injunctive relief and attorney fees); Express Car Wash Corp. v. Irinaga Bros., Inc., 967 F. Supp. 1188 (D. Or. 1997) (The court refused to issue an injunction requiring payment of future response costs, but it added that RCRA citizen suit plaintiff could request injunction ordering defendant to take over the remedial action.).

cover damages for injuries to property or human health, and any penalties recovered for noncompliance would go to the government rather than the individual claimant.[168] A RCRA citizen suit (or its analog under state law hazardous waste statutes) could nonetheless offer a powerful tool to compel cleanup action after a release from an abandoned well due to nearby hydraulic fracturing activity.

By contrast, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) offers a broader set of tools to respond to past contamination yoked with a broad exemption that limits its power at E&P sites, including hydraulic fracturing hits on abandoned wells. CERCLA's core liability provisions allow for the recovery of costs incurred in response to releases of hazardous substances from facilities so long as those costs are incurred consistently with the National Contingency Plan (NCP).[169] Those costs can be recovered from current owners and operators of facilities, past owners and operators (if disposal occurred during their ownership or operation), transporters of hazardous substances to the facility, and persons who arrange for disposal or treatment of the hazardous substances.[170] In theory, this broad net of liability could extend to owners or operators of facilities – either the abandoned well or the hydraulic fracturing site – from which releases of hazardous substances have taken place.[171] The liability in such a case would be strict, in cases with commingled contaminants there would also be joint and several liability. [172]

CERCLA's imposition of liability in this situation, however, is gravely limited by the petroleum exclusion. CERCLA defines "hazardous substances" to exclude petroleum (including crude oil or any fraction of it), natural gas, natural gas liquids, or synthetic gas.[173] As a result, any spills or releases consisting of petroleum or natural gas will not trigger CERCLA liability. The petroleum exclusion, by its terms, does not cover the same oilfield wastes as the E&P exclusion under RCRA,[174] and thus it would not shield owners and operators from CERCLA liability for releases of chemicals, wastes, or other corollary materials from E&P opera-

168. Meghrig v. KFC W., Inc., 516 U.S. 479, 483 (1996) (CERCLA, not RCRA, provides the framework for recovery of past cleanup costs).

169. 42 U.S.C. § 9607(a) (2012).

170. *Id.* § 9607(a)(1)-(4).

171. Sean Joyner, *Superfund to the Rescue – Seeking Potential CERCLA Response Authority and Cost Recovery Liability for Releases of Hazardous Substances Resulting from Hydraulic Fracturing*, 28 J. CONTEMP. HEALTH L. & POL'Y 111, 133, 135-36, 143 (2011) (exploring application of CERCLA authorities to releases of hazardous constituents from hydraulic fracturing sites).

172. Burlington N. & Santa Fe Ry. Co. v. U.S., 556 U.S. 599, 608, 614 (2009) (CERCLA has strict liability; liability is also joint and several unless defendants can demonstrate reasonable basis for apportionment of harm.).

173. 42 U.S.C. § 9601(14) (2012).

174. *See* discussion *supra* note 150.

tions that are not themselves petroleum or natural gas.[175] But the petroleum exclusion removes from CERCLA liability a large portion of the universe of likely contaminants that might result from hydraulic fracturing hits on abandoned wells.[176]

Beyond the petroleum exclusion, CERCLA's definition of "hazardous substance" also includes an exemption that might cover certain types of E&P wastes. CERCLA defines hazardous substances through incorporating by reference the statutory definitions of numerous other environmental statutes, including the definition of "hazardous waste" under RCRA.[177] This incorporation, however, specifically excludes "any waste the regulation of which under . . . [RCRA] has been suspended by Act of Congress."[178] This statutory parenthetical arguably might extend RCRA's E&P exclusion to CERCLA as well. The federal courts, however, have largely concluded that the E&P exclusion under RCRA does not extend to CERCLA hazardous substances as well because (i) the E&P exclusion actually arises from EPA's regulatory action rather than an "Act of Congress" and (ii) hazardous constituents in E&P wastes also qualify as CERCLA hazardous substances under other statutory definitions incorporated by reference in the rest of the statute's definition.[179] As a result, EPA has listed numerous CERCLA sites that contain wastes from oilfield operations which were collected for treatment or disposal at a secondary site.[180] Under this rationale, the non-petroleum portions of contaminants or wastes from hydraulic fracturing operations (such as proppants, chemicals, acids, metals, pipe scale, or other materials) that affected or escaped from nearby abandoned wells would likely fall squarely under CERCLA's jurisdiction.

Despite the facial applicability of CERCLA liability provisions to contamination caused by non-petroleum wastes, applying CERCLA to hydraulic fracturing hits on abandoned wells would face several steep barriers.[181] First, to the extent

175. James Cox, *Revisiting RCRA's Oilfield Waste Exemption as to Certain Hazardous Oilfield Exploration and Production Wastes*, 14 VILL. ENVTL. J. 1, 18 (2003) (arguing need for enhanced RCRA regulation of E&P wastes that falls under CERCLA's petroleum exclusion).

176. Merrill & Schizer *supra* note 82, at 201.

177. 42 U.S.C. § 9601(14) (2012).

178. *Id.* § 9601(14)(C).

179. *See e.g.*, United States v. Hardage, 761 F. Supp. 1501 (W.D. Okla. 1990).

180. The National Priority List of the highest priority CERCLA sites includes numerous facilities that treated or disposed of oil, oily wastes, or refining materials. For example, CERCLA sites that handled oily waste materials include the Hardage Superfund Site, the Double Eagle Refining Site, the U.S. Oil Recovery Site, the Beede Waste Oil Site, and others. *National Priorities List*, ENVTL. PROTECTION AGENCY, https://www.epa.gov/superfund/national-priorities-list-npl-sites-listing-date (last updated June 22, 2018).

181. This analysis will not investigate how hydraulic fracturing operators who impact abandoned wells might face disclosure obligations under the Emergency Preparedness and Community Right-to-Know Act (EPCRA) or analogous state statutes. While these laws can require an operator to report a release of pollutants or regulated materials to an agency, they typically do not impose any substantive obligations to prevent releases, respond to spills, or bear liability for costs related to such releases (beyond CERCLA's provisions). EPCRA also expressly incorporates CERCLA's petroleum exclusion, and

that a government or private party seeks cost recovery or contribution from a mineral estate holder, the federal courts have not clearly resolved whether CERCLA's broad definition of "owner or operator" includes non-possessory mineral estate holders who enjoy the dominant estate.[182] While such mineral estate holders would clearly incur liability as operators to the extent that they conduct drilling and waste handling operations on the surface, a non-operating mineral estate owner may not possess enough indicia of ownership to qualify as an "owner" for CERCLA purposes.[183] Second, because contamination from hydraulic fracturing hitting abandoned wells will likely contain commingled petroleum substances and conventional pollutants outside the petroleum exemption, the segregation of costs related to each source may prove difficult.[184]

Third, CERCLA claimants seeking cost recovery or contribution for contamination from abandoned wells located a significant distance from the hydraulic fracturing site may face the challenging burden of proving that the release of hazardous substances at the site caused the contamination at the remote abandoned well. Given that directional drilling for hydraulically fractured wells can extend for over a mile,[185] and that some abandoned wells will sit amidst numerous hydraulic fracturing operations and undoubtedly contain contamination from prior historical operations,[186] the plaintiffs would need to show that the particular contamination from the abandoned well can be fairly tied to the hydraulic fracturing activity in question. While the federal government would enjoy a reduced burden of proof for a straightforward cost recovery action to respond to contamination,[187] a private party must show by a preponderance of the evidence that all its recoverable costs

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as a result, facility operators do not have to report or inventory petroleum storage or releases as part of their EPCRA obligations.

182. Rachel Blumenfeld, *CERCLA Liability of Mineral Rights Owners – Another Pocket to Pick?*, 19 MEM. ST. U. L. REV. 77, 84-92 (1988); *cf.* John Seymour, *Hardrock, Mining and the Environment: Issues of Federal Enforcement and Liability*, 31 ECOLOGY L.Q. 795 (2004) (discussing analogous situation of U.S. retained ownership of lands under unpatented mining claims).

183. CERCLA holds both "owners" and "operators" liable for response costs incurred at a facility. 42 U.S.C. § 9607(a)(1) (2006). As a result, a passive owner who does not conduct any operations at a facility will incur liability (unless they qualify for exclusions for innocent owners or bona fide purchasers), and a person who operates the facility without any ownership interest will also become liable. United States v. Bestfoods, 524 U.S. 51 (1998) (distinction between "owner" and "operator" in CERCLA context of parent's liability for operations by its subsidiary).

184. Joyner, *supra* note 171, at 133-34; Grace Heusner, Allison Sloto, & Joshua Ulan Galperin, *Defining and Closing the Hydraulic Fracturing Governance Gap*, 95 DENV. L.R. 191, 203 (2017).

185. *See* Abramov, *supra* note 11.

186. *See* discussion *supra* notes 33 to 34 (extent of historical E&P operations in the Permian Basin).

187. The United States need only prove that it incurred its response costs in a manner "not inconsistent" with the National Contingency Plan. 42 U.S.C. § 9607(a)(4)(A) (2006). As a result, after a minimal prima facie showing by the government, the burden of proof typically shifts to the defendants to show that the United States incurred its costs inconsistent with the NCP.

meet the detailed requirements of the NCP.[188] Finally, and more pragmatically, a CERCLA cost recovery action by a private party has several procedural disadvantages. For example, the plaintiff must first incur at least some costs before the court will allow them to seek recovery,[189] and the award of these incurred costs may take years and face substantial legal uncertainty.[190]

These hobbles in CERCLA also tend to extend to analogous state-level statutes that impose liability regimes similar to CERCLA. For example, while Texas has its own State Superfund Program that targets smaller contaminated sites that the federal program would not remediate, the Texas statute contains similar exclusions for petroleum as well as significant procedural constraints on the ability of private plaintiffs to recover their costs from other potentially responsible parties.[191] These procedural hurdles – which include prior notice to affected parties before incurring costs at the site as well as mandatory involvement of state agencies in implementing the remedy before a lawsuit can be filed[192] – can hobble even plaintiffs with compelling claims and significant costs.

2. Discharges to Water

If hydraulic fracturing causes an abandoned well to discharge pollutants to water, that release could violate the federal Clean Water Act or parallel state water quality laws and regulations. The Clean Water Act prohibits the discharge of any pollutant into waters of the United States without a permit or other authorization.[193] While the statute allows states to assume the primary role for implement-

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188. 42 U.S.C. § 9607(a)(4)(B) (2006) (allowing private party to recover response costs incurred "consistent with the national contingency plan"); United States v. Atlantic Research Corp., 551 U.S. 128 (2007) (discussing generally elements for CERCLA cost recovery claims under Section 107 and contribution claims under Section 113).

189. While the courts will award a declaratory judgment on liability that allows an efficient recovery of future incurred costs, the plaintiff must first incur at least some response costs at the site before the courts will hear a CERCLA Section 107 cost recovery action. For a CERCLA contribution action, the plaintiff must first incur costs under a legal judgment or an administrative or judicially approved settlement to resolve its liability. 42 U.S.C. § 9613(f)(1)-(2) (2006).

190. U.S. GENERAL ACCOUNTING OFFICE, GAO-09-656, SUPERFUND: LITIGATION HAS DECREASED AND EPA NEEDS BETTER INFORMATION ON SITE CLEANUP AND COST ISSUES TO ESTIMATE FUTURE PROGRAM FUNDING REQUIREMENTS 21, 31-41, 79-80 (July 2009); Lawrence Hurley, *Lawyers Still Cleaning Up Over Superfund Sites*, N.Y. TIMES (Jan. 3, 2011), https://archive.nytimes.com/www.nytimes.com/gwire/2011/01/03/03greenwire-lawyers-still-cleaning-up-over-superfund-sites-92748.html?pagewanted=2.

191. TEX. HEALTH & SAFETY CODE ANN. § 361.003(11)-(12) (West 1989) (incorporating petroleum exclusion); *id.* § 361.344(a), (c) (requiring TCEQ approval for removal or remedial action, and reasonable attempts to notify other potentially responsible parties, before initiating cost recovery action).

192. *Id.*

193. 33 U.S.C. §§ 1251-1388 (2012).

ing and enforcing water quality standards in lieu of the EPA,[194] those state laws and programs must still at a minimum satisfy federal water permitting standards.[195] If a hydraulic fracturing hit on an abandoned well caused a discharge of pollutants into waters of the United States, the federal or state government (or an affected private party bringing a citizen suit) might seek to enforce the permitting obligation and collect penalties for the discharge.

This type of Clean Water Act enforcement action, however, faces deep challenges. First, and most fundamentally, a discharge of pollutants from an abandoned well may trigger liability for the current owner or operator of the abandoned well rather than the hydraulic fracturing operator. The Clean Water Act requires the person in charge of a facility to obtain a permit for discharges from that facility.[196] The facility here is likely to be the abandoned well site. If that well lies in a different facility or separate property from the fractured well, the operator of the hydraulic fracturing well may not fall under a statutory obligation to obtain a permit for a discharge from a different location. Second, the discharge triggers an obligation to obtain a permit only if it takes place into "waters of the United States,"[197] and that term has fallen into a mire of regulatory and litigative uncertainty.[198] At the least, the federal courts have consistently held that discharges into groundwater do not normally trigger an obligation to obtain a Clean Water Act permit,[199] although that line of precedent is facing new challenges.[200] The Trump Administration's recent decision to reconsider the Clean Water Rule,[201] which attempted to clarify the scope of surface waters that qualified as "waters of the United States," has only added to the uncertainty.

Even if discharges to groundwater do not impact "waters of the United States" under the Clean Water Act, they can nonetheless trigger the regulatory requirements of the federal Safe Drinking Water Act (SDWA) if they potentially affect a drinking water source.[202] Congress trimmed the jurisdictional reach of the

194. 33 U.S.C. § 1342(b) (2006); 40 C.F.R. Pt. 123 (2011).

195. 33 U.S.C. § 1314(i)(2) (2006) (setting out requirements for water quality permitting environmental programs delegated to states): *id.* § 1342(c)(1) (revocation of delegation to states that do not meet requirements).

196. 33 U.S.C. §§ 1311(a), 1342(a), 1362(12) (2006).

197. The Clean Water Act prohibits discharges without permits into "navigable waters," and it in turn defines "navigable waters" as "waters of the United States, including the territorial seas." 33 U.S.C. § 1362(7) (2006).

198. The precise scope of waters that fall within this definition has provoked intense litigation and rulemaking efforts. *See, e.g.*, Rapanos v. United States, 547 U.S. 715 (2006); Definition of "Waters of the United States" –Recodification of Existing Rules, 82 Fed. Reg. 34,899 (July 27, 2017).

199. *See, e.g.*, Rice. v. Harken Expl. Co., 250 F.3d 264 (5th Cir. 2001).

200. The Ninth Circuit recently held that discharges to groundwater that directly affect the quality of adjacent surface waters can constitute a discharge to waters of the United States. Hawai'i Wildlife Fund v. Cty. of Maui, 881 F.3d 754 (9th Cir. 2018).

201. Definition of "Waters of the United States," *supra* note 198.

202. 42 U.S.C. §§ 300f to 300j-27 (2012).

SDWA and its Underground Injection Control (UIC) program, however, by exempting chemicals used in hydraulic fracturing (other than diesel fuel) from any requirements to obtain a SDWA permit.[203] This exclusion effectively hamstrings the use of UIC permits to control the risk of hydraulic fracturing hits on abandoned wells for drilling operations that do not use diesel fuel as a fracking action.

Citizen suits under the Clean Water Act, which could provide a vehicle to impose liability for surface operators whose hydraulic fracturing operations affect nearby abandoned wells, would face many of the same difficulties that confront citizen suits under RCRA.[204] For example, a citizen suit would only impose obligations on surface operators if their E&P activities resulted in a discharge without a permit or in excess of their permit terms. If the discharge met the terms of a permit held by the operator, the Clean Water Act would not hold the operator liable even if the discharge ultimately impaired water quality at or near the abandoned well.[205] Second, the citizen suit would only apply to contemporaneous discharges. If a hydraulic fracturing operation later resulted in water pollution at an abandoned well after the hydraulic fracturing discharges had ceased, the Clean Water Act would not allow a citizen suit to enforce obligations on a wholly past discharge absent special circumstances.[206] Last, as with RCRA, a Clean Water Act citizen suit would not allow the claimant to recover penalties for the violation,[207] and the statute allows the federal government (or a delegated state) to initiate its own enforcement action and take over the citizen suit at a later date.[208]

State water quality statutes offer an independent and broader basis to hold E&P operators liable for pollution at nearby abandoned wells. While the federal Clean Water Act can only reach water discharges to the extent allowed by Congress' constitutional powers, state water laws can reach to all waters held or gov-

203. *Id.* § 300h(d)(1)(B) (excluding from underground injection regulation any injection of hydraulic fracturing fluids (other than diesel fuels) related to oil, gas, or geothermal production activities).

204. 33 U.S.C. § 1365 (2012).

205. The federal courts have offered conflicting decisions on the extent of the permit shield offered by the Clean Water Act. *Compare* Ohio Valley Envtl. Coal. v. Fola Coal Co., LLC, 845 F.3d 133 (4th Cir. 2017) *with* Sierra Club v. ICG Hazard, LLC, 781 F.3d 281 (6th Cir. 2015). While the Clean Water Act requires states to assure that their water bodies attain designated water quality standards, states typically must undergo a waste allocation process to assure that the water body is receiving an appropriate Total Maximum Daily Load of pollutants that will let the water attain its quality standard. This process does not support direct enforcement actions against dischargers who contribute to a water body's failure to reach these standards.

206. Gwaltney v. Chesapeake Bay Found., 484 U.S. 49, 67 (1987).

207. Marcia Gelpe & Janis Barnes, *Penalties in Settlement of Citizen Suit Enforcement Actions Under the Clean Water Act*, 16 WM MITCHELL L. REV. 1025, 1028 (1990); James Thompson, *Citizen Suits and Civil Penalties Under the Clean Water Act*, 85 MICH. L. REV. 1656, 1657 (1987).

208. *See* 33 U.S.C. § 1365(b)(1)(B) (2012) (no citizen suit action allowed if EPA or State "has commenced and is diligently prosecuting a civil or criminal action in a court of the United States, or a State to require compliance with the standard, limitation, or order. . . .").

erned by the state under its plenary or police powers.[209] As a result, state statutes routinely govern discharges to intrastate waters and groundwater located wholly within the state.[210] Some of these statutes, such as Pennsylvania's Clean Streams Law and California's Water Code, set out sweeping obligations to prohibit pollution to any surface or subterranean waters of the state and provide, in some cases, strict criminal liability for violations.[211] Water statutes in oil producing states, including Texas and Louisiana, carry a similarly broad regulatory scope and limitations on discharges to state waters,[212] but these general prohibitions are limited by carve-outs in each state's statutory authorization for E&P operations under state drilling permits.[213]

3. Air Emissions

E&P operations can fall under federal and state limits on their emissions of air pollutants. The Clean Air Act imposes requirements on operators of E&P sites under several programs. For example, an E&P site emitting sufficient criteria air pollutants in a non-attainment area could trigger obligations to obtain a non-attainment new source review (NSR) permit.[214] Alternatively, the same site may

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209. 33 U.S.C. § 1370 (2012); Rapanos v. United States, 547 U.S. 715, 726-30 (2006). To some extent, this truism simply offers the obverse of the federal government's powers under the U.S. Constitution. To the extent that the Constitution does not allocate powers to the federal government, those unenumerated powers remain with the states and subject to their plenary jurisdiction. U.S. CONST. amend. X ("The powers not delegated to the United States by the Constitution, nor prohibited by it to the States, are reserved to the States respectively, or to the people.").

210. *See, e.g.*, TEX. WATER CODE ANN. § 26.001(5) (West 2017) (defining "waters of the state" to include "groundwater, percolating or otherwise"); *id.* § 26.121 (prohibition on any discharges of pollutants into waters of the state).

211. 35 PA. CONS. STAT. § 691.602 (2018); *see also* CAL. WATER CODE §§ 13000-16104 (West 2018); CAL. FISH & GAME CODE § 5650 (West 2018).

212. *See* discussion *supra* note 191; Louisiana Water Control Law, LA. STAT. ANN. §§ 30:2071-2089 (2018).

213. For example, the Texas Water Code broadly prohibits discharges of pollutants into waters of the state, see discussion *supra* note 210, but it also shifts regulatory authority over water discharges by oil and gas production from the Texas Commission on Environmental Quality to the Texas Railroad Commission. TEX. WATER CODE ANN. § 26.131 (West 2017). The Railroad Commission has taken criticism for promulgating regulatory standards laxer than those of other federal and state agencies. *See* SUNSET ADVISORY COMMISSION REPORT *supra* note 163.

214. The federal Clean Air Act requires EPA to set safe levels for certain common air pollutants, such as ozone precursors and particulate matter, as National Ambient Air Quality Standards (NAAQS). 42 U.S.C. § 7409(a) (2012). If an urban area fails to meet the NAAQS for a particular pollutant, EPA and the relevant state must designate that region as a non-attainment area. *Id.* § 7407(d). For areas out of attainment, the Clean Air Act requires large stationary sources to obtain non-attainment New Source Review (NSR) permits that restrict the facility's emissions and help bring the region back into attainment. *Id.* §§ 7502(c)(5), 7503(a). For areas already in attainment, large stationary sources must instead obtain Prevention of Significant Deterioration (PSD) permits that limit emissions in ways to help the region stay in attainment. 42 U.S.C. §§ 7470-7492, 7501-7515 (2018).

incur permit obligations under the Prevention of Significant Deterioration (PSD) program if it emits in an area that meets National Ambient Air Quality Standards (NAAQS).[215] Both programs would impose technology-based limits on the emissions from the E&P operations themselves if they emit enough regulated pollutants to surpass the programs' thresholds to trigger permit requirements.[216] Other programs within the Clean Air Act, including the New Source Performance Standards for the E&P sector, set out parallel and independent emission restrictions.[217] Notably, EPA has already imposed emission limits on new and modified hydraulic fracturing sites through a NSPS standard in 2012 for conventional pollutants.[218] The Risk Management Program requirements imposed by Section 112(r) of the Clean Air Act would require E&P operators of qualified facilities to meet a general duty to maintain a safe working environment,[219] and that same program imposes an obligation to assess potential scenarios that could lead to a release of extremely hazardous substances from the facility.[220]

The fundamental limitation of these federal Clean Air Act requirements is that they apply to operations at the E&P site itself. If the air emissions escape from an abandoned well located at a site that lies outside the boundaries of the E&P facility itself, the Clean Air Act will not apply unless that corollary abandoned well was aggregated with the primary E&P site.[221] The site aggregation is-

215. 42 U.S.C. § 7409(a) (2012).

216. For most sources in areas that meet the NAAQS, a new or modified facility must emit over 100 tons per year of the relevant pollutant to become a major source that must obtain a PSD permit. If the facility lies within a non-attainment area, the threshold can go lower based on the pollutant involved. For example, in extreme non-attainment areas a source can emit as little as 10 tons per year of ozone precursors such as volatile organic compounds or nitrogen oxides. *Id.* § 7511a. Importantly, triggering permitting requirements under these programs will also require the facility operator to obtain an operating permit under Title V of the Clean Air Act as well. *Id.* §§ 7661-7661(f).

217. *Id.* § 7411(b).

218. 40 C.F.R. § 60.5375 (2012). Interestingly, the duty to comply with these rules took effect immediately when EPA proposed the rules in 2011, rather than when EPA finalized them in 2012. 40 C.F.R. § 1 (2017). The Department of Interior's Bureau of Land Management also promulgated rules to tighten operational requirements for hydraulic fracturing operations on public lands (including air emissions limitations), but EPA formally withdrew those regulations in 2017. 82 Fed. Reg. 61,924 (Dec. 29, 2017). That decision to withdraw the BLM rule remains mired in litigation. Melissa Daniels & Keith Goldberg, *California's AG Sues Over Trump Administration's Fracking Repeal*, LAW360 (Jan. 24, 2018), https://www.law360.com/articles/1005217/-calif-ag-sues-over-trump-admin-s-fracking-rule-repeal.
While EPA also has general authority under the Clean Air Act to regulate emissions of specific hazardous air pollutants, 42 U.S.C. § 7412 (2012), Congress limited EPA's authority over oil and gas exploration and production wells by forbidding EPA from aggregating emissions from wells located near each other into a larger source that would require a permit for hazardous air pollutant emissions. *Id.* § 7412(n)(4).

219. 42 U.S.C. § 7412(r)(1) (2012).

220. *Id.* § 7412(r)(7)(B)(ii)-(iii) (2012) (requirement for facilities to prepare Risk Management Plans with reasonable worst scenarios for off-site consequence analyses).

221. *See, e.g.*, Summit Petroleum Corp. v. Envtl. Prot. Agency, 690 F.3d 733, 746 (6th Cir. 2012) (reviewing source aggregation rule in context of dispersed oil and gas production operations).

sue has triggered heated battles between EPA and the oil and gas extraction industry during the past decade,[222] but EPA recently concluded the litigation struggle with a new rule that sets clear geographic boundaries and operational limits on "aggregated" facilities.[223] If the abandoned wells are not operationally linked to the E&P facility and lie outside the EPA policy's geographic limits, the obligations under the PSD, NSR, and NSPS programs will likely not apply at all to emissions from the abandoned well that are potentially linked with a permitted E&P operation.

Again, states have the inherent plenary authority and police power to impose broader and more stringent requirements on air emissions within their borders. Several states, including those with significant E&P activity, have their own state clean air laws that regulate sources too small for federal permitting or for emissions of pollutants for activities not regulated by federal programs.[224] For example, California maintains its own state program for regulating emissions of greenhouse gases from industrial operations, including emissions from E&P operations.[225] While the federal government previously imposed restrictions on E&P operations that burned methane on federal or tribal lands,[226] the Trump Administration has attempted to suspend the implementation of those rules and announced plans to revoke the rules formally.[227] As a result these state air programs can impose significantly broader and more stringent limits on emissions from hydraulic fracturing operations that cause emissions exceedances at affiliated or adjacent abandoned wells, but to date no state has promulgated explicit standards for these types of emissions.

222. *See generally* Charles Wehland & Jennifer Hayes, *The Evolution of EPA's Source Determination Rule*, LAW360 (Aug. 11, 2016), https://www.law360.com/articles/827038/the-evolution-of-epa-s-source-determination-rule.

223. 40 C.F.R. §§ 51.165(a)(i)(ii)(B), 51.166(b)(6)(ii), 52.21(b)(6)(ii), 70.2, 71.2 (2017).

224. For example, if an E&P facility does not emit enough air pollutants to trigger a requirement for a federal Clean Air Act permit, Texas provides several options to permit emissions from minor sources under Texas laws. *See, e.g.*, 30 TEX. ADMIN. CODE § 106.352 (2018) (permit-by-rule for oil and gas handling and production facilities); *id.* § 116.620 (2018) (standard permit rule for oil and gas handling and production facilities).

225. CAL. CODE REG. tit. 17, §§ 95665-95677 (2018).

226. Waste Prevention, Production Subject to Royalties, and Resource Conservation, 81 Fed. Reg. 83,008 (Nov. 18, 2016).

227. The Northern District of California enjoined the Trump Administration's attempt to suspend enforcement of the Waste Prevention Rule while the Bureau of Land Management prepared a formal withdrawal and replacement of the rule. Order Denying Motion to Transfer Venue and Granting Preliminary Injunction, State v. Bureau of Land Mgmt., 286 F. Supp. 3d 1054 (N.D. Cal. 2018) (3:17-CV-07187).

4. Endangered Species

The federal Endangered Species Act (ESA) could apply in two ways to E&P operators whose hydraulic fracturing operations cause emissions or discharges from abandoned wells that pose a risk to threatened or endangered species. First, if the E&P operation requires federal approval or funding, the agency providing the approval would need to undergo a consultation process with the Fish & Wildlife Service to determine whether its decision could jeopardize the protected species.[228] If the biological opinion reviewing the action finds that it jeopardizes the species, the ESA flatly prohibits the federal agency from undertaking the action absent mitigating action.[229] The operator in such circumstances likely could not proceed because the federal government could not issue the required permit or decision needed for the E&P activity.

Second, Section 9 of the ESA forbids the taking of a member of a protected species.[230] If an operator conducts its hydraulic fracturing operations in a fashion that causes an abandoned well to injure or take a protected species, that operator potentially could face strict civil or criminal liability.[231] This liability would extend to both the killing or direct injury to a member of the species, or the destruction or impairment of that species' critical habitat.[232] These potential sanctions, however, would likely first require the federal court to find that the operator's E&P activities proximately caused the injury through the secondary impact on nearby or associated abandoned wells.[233] No court has yet wrestled with this type of fact pattern at a hydraulic fracturing production site.

While the ESA can apply to upstream activities, it remains unclear whether hydraulic fracturing hits on abandoned wells would pose a material compliance or

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228. 16 U.S.C. § 1536(a)(2) (2012).

229. While Section 7(h) of the Endangered Species Act provides to review exemption requests by a high-level interagency panel, 16 U.S.C. § 1536(h) (2012), that authority has rarely been either invoked or granted.

230. While Section 7(a)(2) of the Endangered Species Act flatly prohibits a federal agency from taking actions that would jeopardize an endangered species, those protections extend to threatened species only if the Secretary elects to include them in a special 4(d) listing rule. For example, when the U.S. Fish & Wildlife Service designated the lesser prairie chicken as a threatened species, it included broad prohibitions on any takings of the birds. Endangered and Threatened Wildlife and Plants; Determination of Threatened Status for the Lesser Prairie-Chicken, 79 Fed. Reg. 19,974 (Apr. 10, 2014). Spurred by threatened limits on oil and gas production in the Permian Basin, a large number of companies successfully sued to overturn the special 4d rule. Permian Basin Petroleum Ass'n. v. Dept. of Interior, 127 F. Supp. 3d 700 (W.D. Tex. 2015).

231. *See, e.g.*, Proposed Oil & Gas Coalition MultiState Habitat Conservation Plan for Ohio, Pennsylvania, and West Virginia, 81 Fed. Reg. 85,250 (Nov. 25, 2016) (coalition of oil and gas development companies committed to actions to protect endangered species and their critical habitat that might be harmed by the companies' exploration and development activities, including hydraulic fracturing).

232. Babbitt v. Sweet Home Chapter of Cmtys. for a Greater Or., 515 U.S. 687 (1995).

233. *Id.* at 712-14 (O'Connor, J., concurrence).

liability risk for E&P operators. That said, some potential scenarios could arise in hydraulic fracturing operations which might pose a significant risk of ESA liability. For example, as noted above, a fracturing hit on an abandoned well that causes a release at the surface near critical habitat for a protected species could result in civil or criminal liability.[234] It is also possible for a protected species to live directly in the groundwater or underground aquifer that an inadequate fracturing job could threaten or destroy.[235] And for sites that already have obtained approval for operations from the federal agency through a habitat conservation plan or a candidate conservation agreement, a violation of the obligations of the plan or agreement could obligate the operator to renew efforts to prevent a taking of a species member or injury to critical habitat.[236]

In sum, federal and state environmental statutes and regulatory frameworks can create obligations for E&P operators whose inadequate diligence or operations cause environmental damage at an abandoned well. The scope of this liability, however, is not fully predictable, consistent, or integrated across multiple federal environmental regimes that each contain potentially conflicting obligations.[237] The breadth and strength of those obligations remain highly dependent on individual facts about the materials released, what environmental media that the released chemicals injured, the size and type of fracking operation, and many other factors.[238] Based on these individual circumstances, the availability of numerous ex-

234. For example, concerns about similar disruptions to protected species or damage to their habitat by oil and gas activities have led to heated legal contests to protect the dune sagebrush lizard in West Texas, Kiah Collier, *Environmental Groups Ask Feds to Protect Threatened West Texas Lizard*, TEX. TRIB. (May 8, 2018), https://www.texastribune.org/2018/05/08/environmental-groups-ask-feds-protect-west-texas-lizard/, and the lesser prairie chicken in the Great Plains states, Permian Basin Petroleum Ass'n v. U.S. Dep't of Interior, 127 F. Supp. 3d 700 (2015) (rejecting rule to list lesser prairie chicken as threatened); Endangered and Threatened Wildlife and Plants; Lesser Prairie-Chicken Removed from the List of Endangered and Threatened Wildlife, 81 Fed. Reg. 47,047 (July 20, 2016). The Endangered Species Act requires that the operator acted "knowingly" for either civil or criminal liability to attach. 16 U.S.C. § 1540(a), (b) (2012).

235. For example, the Edwards Aquifer in central Texas hosts several endangered blind salamanders, catfish, and beetles that live solely underground within its waters. *Threatened and Endangered Species in the Edwards Aquifer System*, EDWARDS AQUIFER & DATA RES. CTR., http://www.eardc.txstate.edu/Aquifer-Info/endangered.html (last visited June 8, 2018).

236. 16 U.S.C. § 1539(a) (2012).

237. David Callies, *Regulation of Hydraulic Fracturing*, 49 J. MARSHALL L. REV. 271, 290 (2015) ("A series of other federal laws also play a more attenuated role in the regulation of fracking – although none come close to a comprehensive regulation. As of 2012, fracking was exempt from seven different federal laws."); Heusner et al., *supra* note 184 at 195 ("The current federal hydraulic fracturing regulatory system is both fragmented and incomplete.").

238. For example, a release from an abandoned well affected by a nearby hydraulic fracturing operation could trigger Clean Water Act regulatory requirements if it discharges pollutants into a jurisdictional water of the United States, RCRA if it results in the disposal or treatment of a solid waste that qualifies as hazardous, or the Clean Air Act if the hydraulic fracturing operation emits enough pollutants to require a NSR or PSD permit or triggers obligations under the NSPS program. As a result, similar hydraulic fracturing operations and abandoned wells may receive vastly different treatment

emptions and overlapping federal environmental regulatory permitting regimes make liability and regulatory obligations for fracturing hits on abandoned wells very difficult to discern in some cases. The conflicting oversight and obligations between federal and state agencies, natural resource extraction and environmental agencies, public agencies, and private cost recovery claimants complicate the farrago of regulatory overlap and unclear strategy. As a result, no coordinated plan or framework under federal and state environmental programs exists to guide consistent and effective implementation of standards for fracking operations that might affect abandoned wells or other similar concerns.

More fundamentally, the inconsistent and unpredictable use of tort and environmental regulatory liability faces challenges arising from their post hoc nature and complex factual nature. Plaintiffs wishing to hold an operator accountable for damages caused by hydraulically fracturing near an abandoned well may face dauntingly complex and expensive discovery to establish that the plaintiff's operation specifically caused their damages.[239] Given the complex geologic and technical issues posed by many of these sites, these burdens will almost certainly introduce extensive delays and uncertainty.[240] Even if the plaintiffs can show causation, they would likely still have to wrestle with arguments of contributory negligence, either by adjoining operators who are also fracturing their wells, actions taken (or not) by the plaintiffs themselves, and the negligence (if any) shown by the former operator who closed the abandoned well. The identification, assembly, and allocation of liability among these parties can result in forbiddingly complex litigation.

Last, and most important, the long lesson of environmental law is that contamination, once caused, is often extraordinarily expensive and difficult to cure, even when possible to do so.[241] The better policy is a proactive approach that helps prevent the contamination in the first place at a reasonable cost and without dis-

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based on vagaries of geography, choices of chemicals for E&P operations, and operational capacity of units that emit air pollutants.

239. Peter Menell, *The Limitations of Legal Institutions for Addressing Environmental Risks*, 5 J. ECON. PERSPECTIVES 93, 99-100 (Summer 1991)

> Even when scientific and exposure evidence support a plausible causal connection, the tort system is mired in a requirement of particularized proof of causation . . . . While this requirement can be satisfied readily in cases involving detectable physical interactions, such as automobile accidents, it creates serious problems in cases involving statistical evidence from epidemiological studies.

Id.

240. *Id.* at 100-01.

241. This notion – that the cost of preventing pollution into diffuse environmental media such as water or soil is far cheaper generally than the expense of cleaning up that contamination after it occurs – has become so generally accepted that it has developed into a norm of international environmental law. VED NANDA & GEORGE (ROCK) PRING, INTERNATIONAL ENVIRONMENTAL LAW & POLICY FOR THE 21ST CENTURY 62 (2d ed., 2014) (discussing rise of the Prevention Principle in international environmental law).

couraging beneficial economic activity. The goal is to strike that correct balance. Post-facto remediation of contamination with protracted wrangling over liability is rarely the right call.

III. A Proposed Regulatory Response

In Part II, this Article set forth the growing consensus regarding the structure of a regulatory regime. In Part III, this Article set forth the causes of action that may arise if there were a contamination event due to the hydraulic fracturing of a shale formation close to an abandoned well. However, it is the authors' view that a regulatory response that mitigates the risk upfront is preferable to simply relying on post-contamination remedies. This conclusion is made all the more compelling because current scientific knowledge about reservoirs in these shale formations provides a reasonable ability to predict the area of fracturing interest.[242]

In this regard, current scientific information about shale formations and current hydraulic fracturing treatments provides a reasonable degree of certainty about the probable area of fracturing interest once one knows the pump rates, fluid volumes, and rock characteristics that should be assumed. Thus, instead of bright-line standards[243] or ambiguous standards[244] that are incapable of transparent application, this Article's proposal seeks to provide a methodology for determining the area of fracturing interest that is scientifically valid. In addition, this Article's proposed regulatory framework allocates the responsibility between the regulatory agency and the operator in a manner that ensures transparency and minimizes the duplication of work. As a final preliminary matter, this Article's proposed regulatory framework is modeled for the State of Texas as a test case for two compelling reasons. First, Texas is a state that already has significant electronically-accessible data with respect to prior drilling activity in the Permian Basin.[245] Second, this proposed regulatory framework addresses the exact concerns raised by the Permian

242. For example, commercially available software such as FracPro is marketed and used by the industry for this purpose. *See* FRACPRO, https://www.carboceramics.com/Oil-gas/fracpro (last visited June 30, 2018).

243. *See, e.g.*, ALA. ADMIN. CODE r. 400-1-9-.04(3)(d) (2017) (requires inspection within one-quarter mile radius); ALASKA ADMIN. CODE tit. 20 § 25.283(a)(3) (2018) (requires inspection within one-half mile radius); COLO. CODE REGS. § 404-1-317.r (2017) (requires inspection within 150 feet); NEV. ADMIN. CODE § 522.724(1)(e) (2017) (requires description of all wells within a one-mile radius); 25 PA. CODE § 78.17 (2017) (requires inspection within 1,000 feet); W. VA. CODE R. § 35-8-5.11 (2017) (requires inspection within 500 feet); 055-3 WYO. CODE R. § 1 (LexisNexis 2018) (requires inspection within one-half mile radius).

244. *See, e.g.*, MICH. ADMIN. CODE r. 324.201(2)(g) (2017) (requires an environmental impact statement as part of drilling application but no specific statement about a requirement to investigate for abandoned wells within any specific radius of the proposed new well).

245. *See Oil and Gas Well Records-Online*, TEX. RAILROAD COMMISSION, http://www.rrc.state.tx.us/oil-gas/research-and-statistics/obtaining-commission-records/oil-and-gas-well-records-online/ (last visited June 30, 2018).

Basin, where exponential growth in onshore oil and gas activity is expected to occur[246] in the coming years and where significant abandoned wells already exist. Thus, the proposal is formulated for an area where it arguably is most needed. However, this proposal could be modified and adapted to fit the context of other jurisdictions and thus should provide a helpful paradigm for policy makers who want to assess the efficacy of the regulatory frameworks set forth in Appendix A to this paper.

With the above preliminary comments in mind, the authors propose that the Texas Railroad Commission should amend its existing Rule 5 and Rule 86, which govern the application for a drilling permit for a horizontal well,[247] so that these rules would specifically consider the impact that hydraulically fracturing may have with respect to adjacent wells in the permitting process. Under the current rules, the operator already is required to provide a plat that contains the proposed horizontal well's directional details and the planned perforation intervals.[248] In addition to that already required information, the authors recommend that the Texas Railroad Commission require the operator's initial permit application to include details with respect to each proposed frack stage such as the pump rates, treating pressures, fluid volumes, base fluid type and source, fluid additives, frack fluid viscosity, proppant type/density, and volumes to be pumped.[249]

After submission of this additional information, the Texas Railroad Commission would input this information into a fracturing software program (FracPro or some other commercially available software) to estimate the expected vertical and horizontal growth of the fracture for the proposed well. In this regard, whereas the API report states that the operator's understanding of the geomechanical properties of a reservoir are critical to a proper evaluation of the area of fracturing interest,[250] this paper's regulatory proposal does not leave it to the operator to make assumptions as to the strength, thickness, and the various rock properties of the confining layers because doing so would create needless variation among operators. Instead, the Texas Railroad Commission, with the aid of the state's geologist, should determine the rock characteristics that should be assumed in the calculation of the area of fracturing interest. In this process, the Texas Railroad Commission would need to make standard assumptions as to rock density in the formation where the well is proposed to be located and would need to make assumptions as to

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246. ENERGY INFO. ADMIN., ANNUAL ENERGY OUTLOOK 2018 48 (2018), https://www.eia.gov/outlooks/aeo/pdf/AEO2018.pdf.

247. *See* 16 TEX. ADMIN. CODE §§ 3.5, 3.86 (2018).

248. *See id.*

249. This requirement is not a substantial additional compliance burden because much of this information is already required to be gathered and disclosed on FracFocus under the hydraulic fracturing chemical disclosure requirements that exist under current rules. *See* 16 TEX. ADMIN. CODE § 3.29(c)(2) (2018).

250. *See* ANSI/API RECOMMENDED PRACTICE 100-2, MANAGING ENVIRONMENTAL, *supra* note 59, ¶ 8.5.1.

the containment layer overlaying the proposed area of fracturing interest. However, these modeling assumptions would be made by the regulator in order to ensure consistency and integrity of those assumptions.[251] With this information, the Texas Railroad Commission would then determine whether the area of fracturing interest would likely intersect either a freshwater aquifer or adjacent wells that could become a conduit for the hydraulic fracturing fluid. In this determination process, the Texas Railroad Commission would consult its databases of existing well locations to determine which wells, if any, exist within the area of fracturing interest for the proposed new well.[252] To the extent that the Texas Railroad Commission's electronic databases do not contain well location information for older wells, the Texas Railroad Commission should initiate a focused effort to upload that historical well location data into its electronic databases for legacy wells located within the Permian Basin and South Texas given the expected substantial activity increase that is likely to occur in the coming years in that particular basin.

In the event that the Texas Railroad Commission were to identify offset well(s) within the area of fracturing interest that poses a concern, the Texas Railroad Commission would then tell the operator of the location about each of these adjacent wells that pose a regulatory concern. At this point, the authors propose that the operator then would be required to demonstrate to the Texas Railroad Commission either that its concerns are not valid or must describe the means that the operator would use to mitigate the agency's concerns. If the operator chooses to mitigate the agency's concerns, the authors envision that the operator might pursue one or more of the following options: (i) modify the well path so that the area of fracturing interest (when recalculated) would not intersect with the offset well, (ii) modify the frack design so that the area of fracturing interest (when recalculated) would not extend to the offset well, (iii) agree to engage in onsite monitoring of the offset well to determine if a fracture network intersects an adjacent well and to take appropriate remedial action if such a frack hit were to occur, or (iv) if the well were an abandoned well, then the operator could properly plug the abandoned well and request reimbursement from the Texas Railroad Commission at a predetermined reimbursement rate.

If the Texas Railroad Commission raised a concern, then the authors also suggest that the Texas Railroad Commission would provide notice of the permit ap-

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251. The existing regulatory frameworks that require an upfront modeling exercise places this requirement on operators but doing so creates a lack of transparency or standardization. *See, e.g.*, ALASKA ADMIN. CODE tit. 20, § 25.283(a)(5), (6) (2018); NEV. ADMIN. CODE § 522.728.1(a)(4) (2017) (requires submission of hydraulic fracturing plan for preapproval); 25 PA. CODE § 78a.52a(e) (2018) (requires submission of fracturing plan and analysis of its potential impact on adjacent wells as a condition for obtaining permission to engage in hydraulic fracturing treatment).

252. *E.g.*, *Public GIS Viewer*, TEX. RAILROAD COMMISSION, http://www.rrc.state.tx.us/about-us/resource-center/research/gis-viewers/ (last visited Sept. 9, 2018). This procedure is similar to the one already employed by the Division of Oil and Gas Resource Management in Ohio for drilling in the Utica/Point Pleasant formations. *See* discussion *infra* Appendix A.

plication to all adjacent landowners and operators and afford all interested parties with an opportunity to provide further factual information on the potential risks. An ancillary benefit arising from providing notice to adjacent landowners is that they would be able to take protective steps to mitigate the potential risks to their wells.[253] The authors also propose that the Texas Railroad Commission would also publicly disclose the hearing date on its website.

After receiving the operator's response and any submissions by other interested parties, the Texas Railroad Commission would then make a finding as to whether the proposed hydraulic fracturing operation set forth in the permit application poses a meaningful environmental risk due to the existence of a nearby well. If the regulator determined that a significant risk existed, then the regulator would specify the further remedial actions that would be required.

The authors believe that the Texas Railroad Commission should set forth in its approval the mitigation strategies that it will require the operator to perform. For example, if the area of fracturing interest posed a risk for nearby water sources but the Texas Railroad Commission decides to move forward with approving the operator's submission because it is satisfied that the operator's proposal reasonably mitigates this concern, the Texas Railroad Commission nevertheless could require the operator to conduct baseline water sampling and also require the operator to put tracer elements into its hydraulic fracturing fluid so that post-operation testing of the water source could determine whether the fracturing operation on this particular well did migrate to the water source. The Texas Railroad Commission also could require the operator to conduct post-operation water testing on nearby water sources. If subsequent testing were to determine that a water source was impacted, then the Texas Railroad Commission could then require further remedial effort as appropriate.

In addition, in all events, the Texas Railroad Commission should require the operator to monitor the actual results of the hydraulic fracturing treatment and to notify the regulator if there were an indication of a frack hit within twenty-four hours of the event. Also, the operator would be required to notify the regulator if its actual fracturing operations varied from the estimate set forth in its initial filing. If a significant variance occurred, then the operator would be required to submit the variance data to the Texas Railroad Commission for it to verify the area of

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253. Several states allow notice to be given to adjacent landowners prior to a hydraulic fracturing operation. *See, e.g.*, ALASKA ADMIN. CODE tit. 20 § 25.283 (2018) (requires notice be given to adjacent landowners within one-half mile of the well's intended trajectory); NEV. ADMIN. CODE § 522.728(1) (2017) (requires written notice to all real property owners within one-mile radius); OKLA. ADMIN. CODE § 165:10-3-10(a) (2018) (requires notice of upcoming hydraulic fracturing operation be given to all operators within a one-half mile radius of a perforated interval); 25 PA. CODE § 78a.73(c) (2018) (requires notice be given to all adjacent operators within 1,500 feet radius from the perforations that will be stimulated in the new well); W. VA. CODE R. § 22-6A-10 (2017) (requires notice and hearing opportunity).

fracturing interest and then to determine if further investigation of potentially impacted abandoned wells is needed.

The above regulatory standard maintains the requirement that the operator provide the fracturing data that would be necessary to scientifically determine the expected fracture network and the extent to which the fluids will extend. In this respect the proposal is consistent with the case-by-case regulatory regime envisioned by the EDF Model Regulatory Framework and the case-by-case analysis supported by the API report. However, although the proposal set forth in this paper requires a fact-based upfront analysis, this proposal diverges from either of those earlier proposals in important respects. To begin with, the determination of the area of fracturing interest is done by the regulatory agency using the job-specific data that would be provided by the operator. Thus, by having the regulatory agency determine the area of fracturing interest based on job-specific data, this proposal ensures that the resultant analysis is standardized and not reliant on the business judgment of each specific operator. Furthermore, the regulatory agency would provide the rock density assumptions that should be used for each formation or relevant area of formation, thus again ensuring a standardized analysis among all operators. In addition, if the actual job results materially deviated from the job specifications that were provided as part of the initial application, then the operator would be required to provide this corrected data to the regulatory agency for it to determine whether this deviation indicates that additional wells should have been investigated and to formulate what remedial steps should now be taken. Another key advantage of this proposal is that it uses the actual historic well location data that is available at the Texas Railroad Commission,[254] and sets forth a transparent process that requires an upfront investigation of known wells that are within the area of fracturing interest. Thus, the Texas Railroad Commission would provide a specific listing of the wells that must be investigated in order to confirm that they do not pose a specific risk prior to commencement of the hydraulic fracturing process. Where appropriate, the Texas Railroad Commission could also require offset well monitoring as a condition of its approval.

In addition, unlike the EDF Model Regulatory Framework and the API report, this proposal sets forth an explicit requirement that the operator notify adjacent landowners or offset well operators as part of the permitting process. Thus, this proposal has the further advantage of affording an opportunity for affected parties to take protective actions on their wells prior to the hydraulic fracturing treatment.

254. *See Oil and Gas Well Records*, TEX. RAILROAD COMMISSION, http://www.rrc.state.tx.us/about-us/resource-center/research/online-research-queries/imaged-records-menu/ (last visited July 1, 2018).

Conclusion

The goal of any regulatory regime should be to ensure sustainable energy development occurs in a manner that adequately addresses the environmental concerns posed by modern energy development activities. Because contamination and collateral consequences of pollution can have far-reaching impacts, the public has a vital public policy interest that the industry's development activities utilize best practices. To accomplish that objective, this proposal builds an important collaboration between industry and the regulatory body that oversees that industry. It asks the operator to provide the job-specific information needed to adequately determine the area of fracturing interest, but it does not leave this determination solely to the operator. Instead, the regulatory agency uses its expertise and information to make a fact-based determination of the area of fracturing interest for the proposed hydraulically fractured well. The regulatory agency then utilizes its existing information on locations of nearby wells to identify what wells, if any, should be investigated further. The regulatory agency can then set forth a remediation proposal for the operator to perform. The framework set forth in this article also affords operators with an opportunity to provide their solutions to any regulatory concerns, and other affected parties are afforded an opportunity to participate as well.

By dividing the responsibilities in this fashion, the proposed framework sets forth a regulatory paradigm that attempts to provide transparent and objective results that are not solely dependent on the business judgment of specific operators. Moreover, by requiring this analysis to be done in a scientific manner and by providing an opportunity for notice to be given to affected parties, the proposal also provides an opportunity for potentially affected parties to take precautionary steps with their own wells.

APPENDIX A: SURVEY OF EXTANT REGULATORY RESPONSE

The majority of oil producing states have not required any affirmative identification or inspection of nearby abandoned wells or other naturally occurring transmissive faults as a precondition to obtaining a permit to drill a horizontal well or to engage in a hydraulic fracturing treatment.[255] As to those states that have promulgated explicit rules to address this issue, the regulatory responses have been varied. In this section, this article sets forth an analysis of the various regulatory responses by first analyzing the regulatory regime adopted by Alberta, Canada and then analyzing the regulatory regimes that exist in several U.S. states.

ALBERTA, CANADA

On May 21, 2013, the Alberta Energy Regulator promulgated "Directive 083" in order to set forth requirements for managing subsurface integrity associated with hydraulic fracturing subsurface formations.[256] Directive 083 sets forth requirements to address the following: (i) prevent the loss of well integrity for the well that is hydraulically fractured (in Section 2 of Directive 083), (ii) reduce the likelihood of unintentional interwellbore communication between the well that is hydraulically fractured and an offset well (in Section 3 of Directive 083), (iii) maintain integrity and well control at an offset well if an interwellbore communication occurs (in Section 3 of Directive 083), (iv) prevent adverse effects to non-saline aquifers (in Section 4 of Directive 083), (v) prevent impacts to water wells (in Section 5 of Directive 083), and (vi) prevent surface environmental impacts as a result of a hydraulic fracturing operation (in Section 6 of Directive 083).[257]

As to the requirements to ensure integrity of the well that is the subject of the hydraulic fracturing treatment, Directive 083 requires the operator to design, construct and operate the well to ensure that it maintains integrity throughout the hydraulic fracturing process and to document its analysis of the well's casing and cement and its capability to withstand the pressures of the hydraulic fracturing treatment.[258] Even though Directive 083 requires the operator to document its analysis before commencement of the hydraulic fracturing operation, Directive 083 does not require the operator to submit its analysis to the Alberta Energy Regulator for it to independently evaluate the operator's hydraulic fracturing plan before commencement of the hydraulic fracturing treatment.[259]

255. *See infra* Appendix A.

256. *See* Directive 083: Hydraulic Fracturing – Subsurface Integrity, Alta. Reg. 151/2013 § 1.1, (Can.).

257. *Id.*

258. *Id.* § 2.

259. *See generally* Alta. Reg. 151/2013 (Can.).

As to the requirements to avoid interwellbore communication, the operator is required to determine the area of fracturing interest (which Directive 083 calls the "fracture planning zone"), identify all offset wells within the area of fracturing interest, and to assess the well integrity of each offset well in the area of fracturing interest.[260] As part of its assessment, the operator must conduct a risk-assessment analysis[261] that is designed to determine which wells in the area of fracturing interest are at-risk offset wells.[262] The licensee is required to document its hydraulic fracturing program and maintain at least one copy of its hydraulic fracturing program at the well site that is the subject of its hydraulic fracturing treatment.[263] The licensee is also required to document a well control plan for each at-risk offset well that the licensee has identified and must maintain at least one copy of its well control plan for at-risk offset wells at the well site that is the subject of its hydraulic fracturing treatment.[264] In addition, the licensee is required to affirmatively notify all at-risk offset well licensee and must use all reasonable efforts to develop a mutually acceptable well control plan with each at-risk offset well operator.[265] If an at-risk offset well were an orphaned well where no licensee can be found, then the licensee is required to notify the applicable field office of the Alberta Energy Regulator and coordinate a well control plan with it.[266]

As to the requirements to protect aquifers, the licensee is required to conduct a risk assessment if a hydraulic fracturing operation will be conducted within 100 meters of the base of the groundwater protection.[267] This risk assessment must document the licensee's analysis for the potential of direct fracture communication between the subject well and a non-saline aquifer.[268] In this process, the operator must document its determination of the vertical depth of the top and base of any non-saline aquifers and must determine the fracture network that will be created by the hydraulic fracturing treatment and determine how it will interact with the aquifer.[269] In addition, the licensee is required to determine if there are any geological features or other pathways that may allow or facilitate communication to a

260. *See* discussion *infra* Appendix A.

261. Alta. Reg. 151/2013 § 3.3.2(10)(d) (Can.) (Directive 083 states that the risk assessment methodology should be similar to the methodology prescribed in Interim Industry Recommended Practice 24: Fracture Stimulation: Interwellbore Communication (IRP 24) (Drilling and Completions Committee).).

262. *See id.* § 3.3.

263. *Id.* § 3.3.2(9), (11).

264. *Id.* § 3.3.3(12)-(13).

265. *Id.* § 3.3.4(14)-(15).

266. *Id.* § 3.3.4(16).

267. *Id.* § 4.3.2(19) (Directive 083 defines the base of groundwater protection as a modeled depth calculated as the base of the deepest protected (nonsaline groundwater-bearing) formation plus a 15m buffer.).

268. *Id.* § 4.3.2(20)(a).

269. *Id.* § 4.3.2(20)(f).

non-saline aquifer and must take measures to minimize the risks of any adverse effects on aquifers.[270]

As to water wells and protection of the surface, as a general rule, the licensee is not allowed to conduct hydraulic fracturing treatments within 100 vertical meters of the top of the bedrock surface nor is the licensee allowed to conduct hydraulic fracturing operations within 100 meters vertically from the total depth of any water well.[271]

However, except with respect to at-risk wells, Directive 083 does not require notice to be given to any other affected party in the area of fracturing interest.[272] Moreover, Directive 083 does not require the operator to file its analysis of its hydraulic fracturing plan with the Alberta Energy Regulator nor does it provide a means for affected parties to seek a contested hearing where an affected party could provide its own analysis and data before the hydraulic fracturing operation is commenced.[273]

ALABAMA

Alabama sets forth a general requirement that each hydraulic fracturing treatment must be designed so as to not cause irreparable damage to the oil and gas well or adversely impact any water well or source of fresh water.[274] In furtherance of this objective, the operator must obtain the approval from the Alabama regulatory agency before a well may be hydraulically fractured.[275] To obtain this approval, the operator must submit a wellbore schematic that shows the specifications for the casing and cementing of the well, pressure tests and the depth and intervals of the formation to be fractured, a geophysical and cement bond log, and a description of the hydraulic fracturing design plan.[276] In terms of the hydraulic fracturing design plan, the operator must set forth the anticipated maximum length and orientation of the fractures to be propagated along with the type of fluids and materials that are proposed to be utilized.[277] The operator is required to provide specific information with respect to the chemicals and proppants that will be used in the hydraulic fracturing process.[278] As part of this report, the operator also is required to

270. *Id.* § 4.3.2(20).

271. *See id.* §§ 5.3(23), 6.3(25) (An exception to this 100-meter distance limit exists for using nitrogen as the fracturing fluid.).

272. *See generally* Alta. Reg. 151/2013 (Can.).

273. *Id.*

274. ALA. ADMIN. CODE r. 400-1-9-.04(1) (2017).

275. *Id.* r. 400-1-9-.04(3).

276. *Id.*

277. *Id.* r. 400-1-9-.04(3)(c).

278. *Id.* r. 400-1-9-.04(7)(a). Moreover, the operator is generally required to publish this chemical disclosure statement within thirty days after the hydraulic fracturing treatment on a FracFocus website. *Id.* r. 400-1-9-.04(7)(b).

identify all wells and sources of fresh water within a one-quarter mile radius of the well to be fractured and must conduct a field reconnaissance within this same one-quarter mile radius in addition to reviewing the records of the Geological Survey of Alabama.[279] The operator is also required to provide a written affirmation that the well construction and pressure test results and the geophysical and cement bond logs have been evaluated and that the results of this evaluation indicate that the proposed hydraulic fracturing operation can be conducted without adverse impact on any water well or any other source of fresh water.[280] Alabama's regulatory agency is required to consider whether the proposed hydraulic fracturing operation will be performed underneath an impervious stratum, whether the fracturing fluid will be confined to the formation or will migrate to other zones, and whether the casing's integrity will not be compromised.[281] But Alabama's regulations do not provide a mechanism for landowner engagement prior to the proposed hydraulic fracturing treatment, nor do the Alabama regulations require specific monitoring requirements or set forth specific subsurface stipulations.[282]

Alabama provides heightened requirements when it comes to its approval process for injection wells. In this regard, Alabama requires the operator to provide notice of its intent to operate an injection well and to provide public participation in the hearing that determines the permit application.[283] Alabama requires the operator to determine whether there are defective wells within the area of review (generally within a one-quarter mile radius of the proposed injection well).[284] Moreover, the regulatory agency is empowered to order the operator to take corrective actions with respect to any defective wells as a precondition to its permitting of the injection well.[285] In addition, the operator is required to case and cement injection wells and must pressure test the wells to ensure their integrity before the commencement of any injection operations, and the operator must give the regulatory agency notice of the proposed pressure test prior to its commencement.[286] The operator is also required to continuously monitor and document the basis for the operator's conclusion that the injection well's casing and cement has maintained its integrity throughout its operations.[287] Finally, if the operator becomes aware of any information that would indicate that the injection well has ex-

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279. *Id.* r. 400-1-9-.04(3)(d).
280. *Id.* r. 400-1-9-.04(3)(e).
281. *Id.* r. 400-1-9-.04(3)(e).
282. *See id.* r. 400-1-1 to -7-2.
283. *Id.* r. 400-4-2(3), (9).
284. *Id.* r. 400-4-2(4)(c).
285. *Id.*
286. *Id.* r. 400-4-2(2)(c)-(d).
287. *Id.* r. 400-4-2(6)-(7).

perienced any mechanical or down-hole problem, the operator is required to immediately notify the regulatory agency.[288]

ALASKA

Alaska requires an operator to submit an application for approval before commencement of any hydraulic fracturing operation.[289] Unlike the EDF Model Regulatory Framework, Alaska's regulations (as part of the operator's application to obtain permission to hydraulically fracture a well) require that the operator must provide notice to all landowners, surface owners, and operators within a one-half mile radius of the wellbore's intended trajectory.[290] Alaska's regulations require the operator to affirmatively state to all noticed parties that a complete copy of the operator's hydraulic fracturing application is available to them for inspection upon request.[291] Thus, the Alaska regulations provide an opportunity for adjacent landowners and offset well operators to be informed of the proposed hydraulic fracturing treatment and to participate in the regulatory approval process prior to commencement of the hydraulic fracturing treatment and to take precautions to protect their own wells during the hydraulic fracturing treatment.

Much like the EDF Model Regulatory Framework, Alaska's regulations require the operator to submit detailed information about the hydraulic fracturing treatment prior to the approval of such treatment.[292] In the application for regulatory approval, the operator must provide a plat that sets forth the following: (i) the subject well's location, (ii) the location of each water well located within a one-half mile radius of the subject well's surface location, and (iii) for all types of wells, the location for each well penetration within a one-half mile of the current or proposed wellbore trajectory and fracturing interval.[293] The operator's application must also identify each freshwater aquifer located within a one-half mile radius of the current or proposed wellbore and provide a plan for detailed baseline water sampling of water wells before the hydraulic fracturing operations are conducted.[294] The application for approval must also set forth the location of any known or suspected fault or fracture that may transect the confining zones along with information to support the operator's determination that the known or suspected fault or fracture will not interfere with the containment of the hydraulic fracturing fluid.[295]

After setting forth the geological information listed above, the operator is then required to provide detailed information about the proposed hydraulic fracturing

288. *Id.* r. 400-4-2(10).
289. ALASKA ADMIN. CODE tit. 20, § 25.280(f) (2017).
290. *Id.* § 25.283(a)(1).
291. *Id.* § 25.283(a)(1).
292. *Id.* § 25.283(a)(12) (2017).
293. *Id.* § 25.283(a)(2).
294. *Id.* § 25.283(a)(3)-(4).
295. *Id.* § 25.283(a)(11).

operation. In this aspect of its submission, the operator is required to set forth the maximum anticipated implications to the formation, the integrity of the subject well and of all aquifers, the impact of the fracturing treatment on the integrity of wells within a one-half mile radius of the subject well's wellbore, and the impact of the fracturing treatment on the subject well and to all known faults within a one-half mile radius.[296] Specifically, the operator's application must provide detailed information about the casing and cementing of the subject well to show that it has sufficient integrity[297] to withstand the proposed hydraulic fracturing operation.[298] The operator must provide a detailed analysis of the fracturing program that includes - among other things - the maximum anticipated volumes of fluids, the maximum anticipated pressures that will be achieved in the hydraulic fracturing operation, and the maximum anticipated fracture height and length.[299] The operator must demonstrate that the hydraulic fracturing fluids will be confined to the approved formations.[300] The operator's report also must set forth detailed documentation with respect to the chemical substances that will be used in the hydraulic fracturing operations.[301] In addition, after the hydraulic fracturing treatment is completed, the operator is required to submit a post-treatment report that sets forth detailed information about the actual results of the fracturing operation and the actual chemical substances and their volumes used in the fracturing treatment.[302]

Consistent with the EDF Model Regulatory Framework, the Alaska regulations require the operator to gather baseline water sampling for all water sources within a one-half mile radius of the wellbore trajectory and must submit this baseline information to the commission as part of its request for approval for the hydraulic fracturing treatment.[303]

The Alaska regulations also set forth detailed rules with respect to the monitoring of the hydraulic fracturing treatment. In this regard, if pressures in the hydraulic fracturing treatment exceed 500 pounds per square inch, gauge (psig) above the anticipated pressures, the operator must provide notice of this event to the commission within 24 hours of its occurrence and must implement corrective actions that includes a heightened level of prescribed surveillance activities that must be conducted, and the operator is required to file a detailed incident report within 15 days of the episode.[304]

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296. *Id.* § 25.283(a)(3), (6), (11)
297. *Id.* § 25.283(a)(6)-(10).
298. *Id.* § 25.283(a)(5)-(6).
299. *Id.* § 25.283(a)(12)-(13).
300. *Id.* § 25.283(e).
301. *Id.* § 25.283(a)(12)(C).
302. *Id.* § 25.283(b)-(d), (f), (h).
303. *Id.* § 25.283(a)(3)-(4).
304. *Id.* § 25.283(g).

Consistent with the EDF Model Regulatory Framework, the Alaska regulations require the operator to file a post-hydraulic fracturing treatment report that provides information about the actual fracturing area of interest, the actual fracturing fluids used and the pressures obtained in the treatment.[305] Additionally, the application must set forth detailed information that demonstrates that the well's casing and cement integrity were not compromised by the hydraulic fracturing treatment.[306] In addition, the Alaska regulations set forth the possibility that the commission may require the operator to conduct post-treatment water sampling of water wells after the hydraulic fracturing operations are concluded when the commission determines that such post-treatment sampling is warranted.[307]

Alaska's regulations for disposal wells face heightened requirements. In this regard, the operator is required to provide detailed mapping of all aquifers, wells, and any other feature within 5,000 meters of the disposal well that could allow the injected substances to reach a water source.[308] And, after detailing this subterranean topography, the operator then must demonstrate that there is a 90 percent probability that the thickness and permeability of the geological strata is such that the disposal site will prevent contact of the injected substances with any aquifer or any source of surface water within 1,000 years.[309]

COLORADO

In 2015, the Colorado Oil and Gas Conservation Commission adopted new rules for permitting wells that are within 150 feet of an existing well.[310] Under the new rules, an operator must perform an anti-collision evaluation with respect to all active offset wells that have the potential of being within 150 feet of a proposed well prior to the commencement of drilling operations on the proposed well and submitted to the commission as part of its approval request.[311] For purposes of this rule, if a well will be hydraulically fractured within 150 feet of an adjacent well, then the evaluation must determine that no portion of the well's treatment interval will extend within 150 feet of an offset well without notification and consent of the existing well's operators.[312] Furthermore, if a well or its treatment interval were to extend within 150 feet of an offset well, then the operator must obtain the written consent of the offset operator and attach that written consent to the operator's application for a permit to drill the proposed well.[313] Colorado's regulatory rules re-

305. *Id.* § 25.283(h).
306. *Id.* § 25.283(a)(5)-(6).
307. *Id.* § 25.283(j).
308. *Id.* § 63.130(c).
309. *Id.* § 63.130(b).
310. *See* COLO. CODE REGS. § 404-1-317.r to .s (2018).
311. *Id.* § 404-1-317.r.
312. *Id.* § 404-1-317.r to .s.
313. *Id.* § 404-1-317.s.

quire baseline water sampling of water sources within a one-half mile of a proposed well,[314] but Colorado's regulations require the operator to affirmatively notify offset well operators or adjacent landowners that are more than 150 feet away from the wellbore's treatment interval.[315] Furthermore, the Colorado regulations currently do not require specific filings as to the hydraulic fracturing treatment.[316]

Colorado's rules on injection wells are more stringent. In this regard, Colorado requires an operator of a proposed injection well to provide a plat that shows all wells including, dray and abandoned wells, that are within a one-quarter mile of a proposed injection well.[317] The operator is also required to detail the location of all underground sources of drinking water.[318] Consistent with the requirements imposed on operators who seek a permit to conduct a hydraulic fracturing operation, the operator of an injection well is required to provide the specifications of the casing and cement of the well and a statement of the chemicals that will be injected in the secondary recovery operation.[319]

MICHIGAN

An operator is required to notify the Michigan's Department of Environmental Quality, Office of Oil, Gas and Minerals Division at least forty-eight hours in advance of conducting any hydraulic fracturing operations,[320] but preapproval of those operations is not required.[321] The operator is required to monitor injection and annulus pressures[322] and must record the volumes of water[323] and the chemical substances[324] used in the hydraulic fracturing treatment. The operator also must file a report with the state regulatory agency with this information within sixty days of completing the hydraulic fracturing treatment.[325] If during the hydraulic fracturing treatment the annulus or injection pressures indicate a lack of well integrity, then the operator is required to immediately suspend the hydraulic fracturing operations and to notify the Michigan regulatory agency.[326] Furthermore, although Michigan requires the operator to file an environmental impact statement as part

314. *Id.* § 404-1-609(b).
315. *Id.* § 404-1-317 to -1-401.
316. *See id.*
317. *Id.* § 404-1-401.b.
318. *Id.* § 404-1-401.b(4)(B).
319. *Id.* § 404-1-401.b(4)(D).
320. *See* MICH. ADMIN. CODE r. 324.1405(1) (2017).
321. *Id.*
322. *Id.* r. 324.1405(2).
323. *Id.* r. 324.1405(5).
324. *Id.* r. 324.201(2)(c).
325. *Id.* r. 324.1405(2)(b).
326. *Id.*

of its drilling permitting process,[327] the Michigan rules do not explicitly require the operator to investigate the possible existence of abandoned wells or other naturally occurring transmissive faults that may exist within the area of fracturing interest. The nonexistence of an affirmative obligation to investigate for transmissive faults prior to hydraulic fracturing operations diverges from Michigan's permitting process with injection wells.

Specifically, for injection wells, an operator must submit a plat that details the location and total depth of the proposed injection well and each abandoned, producing or drilling well and dry hole within 1,320 feet of the proposed injection well.[328] Moreover, the operator of an injection well, as a precondition for obtaining a permit for the injection well, must provide the plugging records for abandoned wells and the casing, sealing, and completion records of all other wells within 1,320 feet of an injection well, and the operator must also submit a plan reflecting the affirmative steps or modifications that the operator believes are necessary to prevent proposed injected fluids form migrating up, into, or through inadequately plugged, sealed, or completed wells.[329] Furthermore, Michigan does not require the operator to notify adjacent offset well operators or adjacent landowners prior to conducting hydraulic fracturing operations.

NEVADA

An operator is required to include in its application for a drilling permit a description and location of each water source[330] and each fault[331] located within one-mile radius of a proposed well. In addition, the operator is required to displace the surface well site at least 300 feet away from any known perennial water source.[332] Nevada's regulations also require the operator to provide written notice to each owner of real property located within a one-mile radius of the hydraulic fracturing operation. The operator must provide this notice at least fourteen days prior to the commencement of the hydraulic fracturing treatment.[333] The operator must file an affidavit as to the integrity of the well's casing and cement and must aver that each strata that is required to have been isolated has in fact been isolated.[334] The operator is also required to submit the proposed hydraulic plan to the relevant regulatory agency for approval.[335] The operator must also publicly disclose all chemicals

327. *Id.* r. 324.201(2)(g).

328. *Id.* r. 324.201(2)(k)(i).

329. *Id.* r. 324.802(d).

330. *See* NEV. ADMIN. CODE § 522.724(1)(d). This 1-mile radius can be extended to a larger radius by the Nevada regulatory agency.

331. *Id.* § 522.724(1)(e).

332. *Id.* § 522.726(1).

333. *Id.* § 522.728(1).

334. *Id.* § 522.728 (1)(a)(3).

335. *Id.* § 522.728(1)(a)(4).

that will be used in the hydraulic fracturing treatment.[336] The operator is required to monitor and record all well head pressures including each annular space pressure and must not utilize hydraulic pressures that exceed the capability of the well's casing.[337] The operator is also required to conduct baseline water sampling within six months to a year prior to the commencement of hydraulic fracturing operations and then must obtain subsequent water samples after the hydraulic fracturing treatment and must notify the owner of the water source and the state regulatory agency if the operator finds that the water source contains a listed substance or has otherwise degraded in water quality when compared to the pre-hydraulic fracturing baseline water sample.[338]

The operator is also required to provide copies of the test results of each sample to the state regulatory within thirty days after receiving the test results.[339] The operator is required to immediately stop the hydraulic fracturing process and notify the Nevada regulator if the actual annular space pressure reading indicates that the well's casing or cement has been compromised.[340] Nevada also provides that the operator is required to provide a report to a publicly available website that sets forth details about the hydraulic fracturing process and the particular well that was hydraulically fractured.[341]

NORTH DAKOTA

In North Dakota, the state regulations do not explicitly require investigation of potential transmissive faults prior to conducting hydraulic fracturing operations, nor is the operator required to give notice to adjacent landowners or offset well operators prior to conducting such operations.[342] The North Dakota regulations set forth an overall requirement that the operator ensure the integrity of the well's casing and cement throughout the hydraulic fracturing operations.[343] To this end, the regulations require the operator to pressure test and evaluate the thickness of the casing,[344] including intermediate casing,[345] and must utilize cement evaluation tools to evaluate cement[346] integrity prior to conducting any hydraulic fracturing treatment. The results of these tests must be compared to the API specifications, and the casing cannot be subjected to pressures that exceed 85% of the API rating

336. *Id.* § 522.728(1)(c).
337. *Id.* § 522.728(2).
338. *Id.* § 522.722(3)-(9).
339. *Id.* § 522.722(10)-(11).
340. *Id.* § 522.728(2).
341. *Id.* § 522.728(4).
342. *See generally* N.D. ADMIN. CODE 43-02-03-27.1 to -05-14 (2017).
343. *See, e.g.*, *id.* at 43-02-03-27.1.
344. *See id.* at 43-02-03-27.1(2)(b).
345. *Id.* at 43-02-03-27.1(2)(d).
346. *Id.* at 43-02-03-27.1(2)(c).

for such casing.[347] The operator is required to notify the regulatory agency if pressure readings during the hydraulic fracturing operation indicate that the well's casing may have been compromised.[348] Within sixty days of completion of the hydraulic fracturing treatment, the operator is required to disclose the chemicals uti- utilized in the hydraulic fracturing process on a publicly-available website called "FracFocus."[349]

Heightened investigatory requirements are imposed on operators of an injection well. In this regard, as a precondition for obtaining a permit for an injection well, North Dakota regulations require the operator to provide a plat depicting the location of the proposed injection well and all current producing wells, plugged wells, abandoned wells, drilling wells, dry holes, and waters wells within a one-quarter mile radius of the proposed injection well.[350] In addition, North Dakota's regulations require the operator to provide appropriate geological data for the injection zone and for the confining zones along with the estimated fracture pressure of the top confining zone.[351] The operator must disclose the maximum injection pressure that will be experienced in the zone and must disclose the geological depth of the proposed injection zone to the base of the underground source of drinking water.[352] The operator of an injection well is also required to determine the land ownership within a one-quarter mile radius of the proposed injection well and must provide an affidavit indicating that the operator provided notice of the proposed injection well to these adjacent landowners.[353] The operator also must provide a report detailing corrective actions that are needed[354] and will be taken[355] for any wells penetrating the injection zone within one-quarter mile of the proposed injection well. The North Dakota regulations affirmatively state that a permit for an injection well shall not be issued unless the regulatory agency is satisfied that the proposed injection well will not endanger any underground source of drinking water.[356]

OHIO

In Ohio, there does not appear to be an explicit regulatory rule that deals with abandoned wells that are located close to a well that will be hydraulically fractured. However, the Division of Oil and Gas Resources Management governs oil and gas

347. *Id.* at 43-02-03-27.1(2)(a).
348. *Id.* at 43-02-03-27.1(3).
349. *Id.* at 43-02-03-27.1(2)(i). The FracFocus website can be accessed at FracFocus.org.
350. *Id.* at 43-02-05-14(2)(b).
351. *Id.* at 43-02-05-14(2)(c).
352. *Id.* at 43-02-05-14(2)(c) to (f).
353. *Id.* at 43-02-05-14(2)(j) to (l).
354. *Id.* at 43-02-05-14(3)(f).
355. *Id.* at 43-02-05-14(13).
356. *Id.* at 43-02-05-14(9).

development in Ohio and as part of its permitting process requires applicants horizontal wells in the Utica/Point Pleasant Formation to provide a plat prepared by a registered surveyor that includes the locations of all vertical oil and gas wells within 500 feet of the entire proposed horizontal borehole.[357] With this information, geologists in the Division of Oil and Gas Resources Management compare well locations shown on the plat with its own records during the permit review process.[358] If any well penetrates the Utica/Point Pleasant interval (Cambro-Ordovician wells), the permitting geologists must review well construction records for active wells and the plugging records for abandoned wells to determine if the Utica/Point Pleasant interval is isolated by cement in the wellbore.[359] If the interval is not isolated, the operator may be required to reposition the well's location to avoid the possibility of communication or work out a deal with the offset well owner to plug the nearby well.[360]

In contrast to the lack of explicit regulatory guidance with respect to hydraulic fracturing treatments performed near abandoned wells, Ohio sets forth explicit rules for operators seeking a permit for an injection well. When it comes to injection wells, the operator is required to investigate the area within a one-half mile radius or a one-quarter mile radius depending on injection rates.[361] The operator is also required to identify all landowners of the subject tract[362] and all owners or operators of wells located within the area of review.[363] The operator is required to identify all other wells that penetrate the formation within the area of review regardless of their status.[364] And, if those other wells create a contamination risk, then the operator is required to take corrective action with respect to those other wells.[365] Moreover, the Ohio regulatory division publishes notice of a hearing to consider the injection well permit and sends notice of that hearing to all owners and operators of wells within the area of review.[366] A formal process is set forth for any person to submit comments or to make objections to the permitting of the injection well, and the regulatory agency is required to make a substantive determination as to each objection that it receives.[367] In addition, the Ohio regulatory rules

357. *See generally* OHIO ADMIN. CODE 1501:9-1-04 (2017).

358. E-mail from Steve Opritza, Permitting Manager, Ohio Dep't of Nat. Res., Div. of Oil and Gas Res. Mgmt., to Bret Wells, George Butler Research Professor and Professor of Law, Univ. of Hous. Law Ctr. (July 11, 2018, 11:58:28 CDT) (on file with author).

359. *Id.*

360. *Id.*

361. OHIO ADMIN. CODE 1501:9-5-05(B) (2017).

362. *Id.* at 1501:9-5-05(C)(2).

363. *Id.* at 1501:9-5-05(C)(3).

364. *Id.* at 1501:9-5-05(D)(4).

365. *See id.* at 1501:9-5-05(C)(11).

366. *Id.* at 1501:9-5-05(E)(1).

367. *Id.* at 1501:9-5-05(E)(2).

explicitly require the operator of an injection well to conduct its operations in a manner that will not cause surface contamination or contamination of any water source.[368]

OKLAHOMA

On February 28, 2017, the Oklahoma Corporation Commission adopted a new rule that required all operators to provide notice to the surface owner and to each operator of wells that are located within one-half mile radius of a perforated interval of a proposed well that is approved to be hydraulically fractured.[369] The Oklahoma rules also require the operator that conducts the hydraulic fracturing operation to provide a post-operation report that details the chemicals used in the hydraulic fracturing treatment.[370] But, Oklahoma's rules do not explicitly address the risk posed by abandoned wells located near wells that are subjected to a hydraulic fracturing treatment.[371]

Oklahoma has explicit requirements with respect to injection wells. In this regard, the operator is explicitly required to provide a plat that shows the location of a proposed injection well and all other wells including abandoned wells and dry holes and the names of all offset well operators within the area encompassed by the project.[372] In addition, as a condition of obtaining approval for an injection well, an operator is required to remediate any unplugged or improperly plugged abandoned well or borehole that is located within a one-quarter mile of the proposed injection well.[373]

PENNSYLVANIA

Pennsylvania has a robust set of due diligence requirements that the operator must satisfy as a pre-condition to obtaining approval to engage in a hydraulic fracturing treatment. Pennsylvania's rules require an operator to identify the surface and bottom hole locations of any active, inactive, orphan, abandoned, or plugged and abandoned wells that have a well bore path within 1,000 feet from the surface and the entire length of a horizontal well bore that is proposed to be hydraulically fractured.[374] In identifying these adjacent wells within this stipulated area of review, the operator is required to review all well databases that are available, review historical source information, and also must submit questionnaires provided by the Pennsylvania regulatory agency by certified mail to all landowners whose property

368. *Id.* at 1501:9-5-06.
369. OKLA. ADMIN. CODE § 165:10-3-10(a) (2017).
370. *Id.* § 165:10-3-10(c).
371. *See generally id.* §§ 165:10-3-10 to -5-15.
372. *Id.* § 165:10-5-4(b).
373. *Id.* § 165:10-5-15(b)(1)(D).
374. 25 PA. CODE § 78a.52a(a) (2016).

is within the area of review.[375] Moreover, Pennsylvania's rules require the operator to provide notice of proposed hydraulic fracturing treatment to operators of active, inactive, abandoned, and plugged and abandoned wells that likely penetrate within 1,500 feet from the perforations that are proposed to be stimulated through hydraulic fracturing.[376] The operator must do each of the following: (i) submit a report that sets forth a plat showing the location of all wells identified in the area of review, (ii) submit proof that the operator submitted the required questionnaires to all adjacent landowners, (iii) documents the monitoring plan for wells that are required to be monitored, (iv) sets forth the best available information on the true vertical depth of all identified wells along with the source for this information, and (v) sets forth the best available information of evidence of failed well integrity for any identified well either with the drilling permit application or prior to thirty days before the well will be drilled if submitted separately.[377] Based on the submitted information, additional requirements could be imposed on the operator as a result of the submitted information as a pre-condition to getting permission to hydraulically fracture the subject well.[378]

The operator who proposes to hydraulically fracture a new well must ensure that all identified orphaned, abandoned, or abandoned and plugged wells located within the area of review must be visually monitored during stimulation activities.[379] In addition, the Pennsylvania rules require that operators of all offset wells within 1,500 feet from any stimulated perforation to be visually monitored during the hydraulic fracturing treatment.[380]

Pennsylvania's rules do not require baseline water sampling prior to hydraulic fracturing operations, but they do set forth procedural benefits to the operator if baseline water samples are taken.[381] In this regard, a well operator who wishes to preserve its defenses that a water supply was polluted prior to the alteration of a well by a hydraulic fracturing treatment must have a predrilling survey of existing water quality conducted by an independent Pennsylvania-accredited laboratory.[382] Moreover, a person who wants to document the quality of a water supply to support a future claim that a hydraulic fracturing operation polluted a water source is also entitled to have a survey conducted by an independent Pennsylvania-accredited laboratory prior to the hydraulic fracturing treatment to provide a baseline survey of the water source.[383]

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375. *Id.* § 78a.52a(b).
376. *See id.* § 78a.73(c).
377. *See id.* § 78a.52a(c)-(d).
378. *Id.* § 78a.52a(e).
379. *See id.* § 78a.73(c).
380. *Id.* § 78a.73(c).
381. *See generally id.* § 78a.52.
382. *Id.* § 78a.52(a), (c).
383. *Id.* § 78a.52(b).

In addition, the operator is required to immediately notify the Pennsylvania's Department of Environmental Protection with respect to any change to a well being monitored, of any treatment pressure or volume changes indicative of abnormal fracture propagation at the well-being stimulated or if otherwise made aware of a confirmed well communication incident associated with a hydraulic fracturing treatment.[384] If such an incident occurs, the operator is required to cease stimulating the well and must immediately take steps to prevent pollution of waters or discharges to the surface.[385] Moreover, if such an event were to occur, the operator is not allowed to resume stimulation of the well until it receives an approval to do so from the regulatory agency.[386] In addition, if a hydraulic fracturing operation alters an orphan well, abandoned, or plugged and abandoned well, the operator has an affirmative duty to plug the altered well or place the altered well into production in accordance with the regulatory requirements set forth by the Pennsylvania Department of Environmental Protection.[387] In addition, Pennsylvania's Department of Environmental Protection recently issued detailed guidelines that further clarify these regulatory requirements.[388]

Unlike the EDF Model Regulatory Framework and the Alaska rules, the Pennsylvania rules do not require the operator to file a detailed analysis that demonstrates the operator's basis for believing that the well's casing and cement will maintain integrity throughout and after the hydraulic fracturing treatment.[389] Instead, the Pennsylvania rules simply state that the operator "shall construct and operate the well . . . to ensure that the integrity of the well is maintained and health, safety, and environment and property are protected"[390] and to prevent the migration of hydrocarbons or hydraulic fracturing fluids from polluting fresh groundwater.[391]

TEXAS

Texas has charged its Railroad Commission with regulating oil and gas operations in the state,[392] and in 2013 the Texas Railroad Commission amended its regulations that address the casing, cementing and completion of oil and gas wells in response to growing concerns about the integrity of wells that will undergo a hy-

384. *See* PA. DEP'T OF ENVTL. PROT., GUIDELINES FOR IMPLEMENTING AREA OF REVIEW (AOR) REGULATORY REQUIREMENT FOR UNCONVENTIONAL WELLS 25-29 (2016).

385. *Id.*

386. *See* 25 PA. CODE § 78a.73(c) (2016).

387. *Id.* § 78a.73(d).

388. *See* PA. DEP'T OF ENVTL. PROT., *supra* note 384 at 1.

389. *See generally* 25 PA. CODE § 78a.52-.73 (2016).

390. *Id.* § 78a.73(a).

391. *Id.* § 78a.73(b).

392. *See generally* TEX. NAT. RES. CODE ANN. § 86.042 (West 1977).

draulic fracturing treatment.[393] Under the revised rules, Rule 13(a) prescribes a general obligation on the operator to ensure that Rule 13's intent is satisfied, which intent includes the following: (i) the casing is securely anchored so that the well is effectively controlled at all times, (ii) all usable water zones are to be isolated and sealed off to effectively prevent contamination, and (iii) fluids are prevented from migrating out of the production zone to other zones or from migrating behind the casing.[394] To achieve this objective, Rule 13 sets forth detailed specifications for the casing and cementing of wells across all potential production zones and potential flow zones.[395] Furthermore, if a well is going to be hydraulically fractured, the operator is required to pressure test the casing up to the maximum pressure that will be used in the hydraulic fracturing treatment, and the operator is required to notify the district office of the Texas Railroad Commission within twenty-four hours if the pressure test is failed.[396] During the hydraulic fracturing treatment, the operator also has an obligation to monitor all annuli during the hydraulic fracturing treatment and must suspend operations if actual pressure or the actual thermal transfer readings deviate from those anticipated by the hydraulic fracturing plan.[397]

In addition, Rule 13 sets for heightened requirements for a "minimum separation well," which Rule 13(a)(1)(L) defines as a well that will be hydraulically fractured and to which the vertical distance between the base of a useable water supply and the top of the formation that will be stimulated is less than 1,000 vertical feet.[398] Rule 13 also allows the Texas Railroad Commission to classify a well that falls outside this 1,000 vertical feet distance limit as a minimum separation well if the agency concludes that the geological data indicates that an inadequate separation exists between the base of a usable water supply and the top of the formation in which hydraulic fracturing treatments will be conducted.[399] If a hydraulic fracturing treatment will be performed on a well that is classified as a minimum separation well, then more stringent cementing requirements and more rigorous testing requirements are imposed on the operator.[400]

However, what is striking about Rule 13 is what it does not include. For example, Rule 13 does not explicitly require the operator to conduct specific due dili-

393. *See* 16 TEX. ADMIN. CODE § 3.13, 38 Tex. Reg. 3542 (June 7, 2013); *see also* Proposed Amendments to 16 TEX. ADMIN. CODE § 3.13, 37 Tex. Reg. 7021 (Sept. 7, 2012) (includes an analysis of the agency's stated desire to strengthen its standards with respect to hydraulic fracturing treatments to better protect water sources including subsurface water sources).

394. *See* 16 TEX. ADMIN. CODE § 3.13(a) (2016).

395. *Id.* § 3.13(4).

396. *Id.* § 3.13(7).

397. *Id.* § 3.13(7)(C).

398. *Id.* § 3.13(1)(L).

399. *Id.*

400. *Id.* § 3.13(7)(D).

gence to investigate the existence of abandoned wells that are near the area of fracturing interest. In contrast, in the context of disposal wells[401] and injection wells,[402] before conducting its operations on a disposal well or an injection well, the operator is required to affirmatively investigate the public records to identify all abandoned wells that are within a one-quarter mile radius of the disposal well or injection well.[403] In addition, in the context of a disposal well or an injection well, the Texas Railroad Commission rules require the operator to determine whether the identified abandoned wells were properly plugged and to identify in its permit application each abandoned well that was not properly plugged.[404] Thus, lower due diligence obligations are placed on an operator to identify nearby abandoned wells or some other naturally occurring transmissive fault for wells that will be subjected to a hydraulic fracturing treatment than are placed on operators who want to operate disposal wells or injection wells.

Rule 13 does not require any actual notice to landowners, offset well operators, or the owner of water sources prior to or after the conduct of a hydraulic fracturing treatment. This lack of notice to affected parties for wells that will be hydraulic fractured diverges from the procedural rights afforded to affected parties with respect to disposal wells or injection wells. In this regard, with respect to disposal wells[405] and injection wells,[406] the Texas Railroad Commission requires the operator in the context of those wells to provide notice to affected parties within a one-half mile radius of the proposed well prior to its permitting for either a disposal well or an injection well. In addition, the Texas Railroad Commission provides affected parties, with respect to injection wells[407] and disposal wells,[408] an opportunity to participate in a hearing prior to the issuance of a permit for an injection well or disposal well. In contrast, the Texas Railroad Commission provides no obligation to provide notice to affected parties as part of the hydraulic fracturing permitting process, and this lack of a right to notice diverges from the obligations that are placed on operators of disposal wells or operators of injection wells as operators in those contexts are required to provide notice to all affected parties as part of the permitting process.[409]

401. *Id.* § 3.9(7).

402. *Id.* § 3.46(e)(1).

403. *Id.*

404. *Id.* § 3.9(7)(A).

405. *See id.* § 3.9(5)(A).

406. *See id.* § 3.46(c)(1), (3) (The Railroad Commission can expand the class of persons entitled to notice if it believes that another class of parties may represent an additional affected party.).

407. *Id.* § 3.46(c)(5).

408. *Id.* § 3.9(5)(e).

409. *Compare supra* note 253 *with supra* notes 245 to 248.

Finally, the Texas rules do not require the operator to conduct any pre-treatment baseline water sampling or post-hydraulic fracturing treatment water sampling.[410]

Thus, although the Texas Railroad Commission's 2013 amendments to Rule 13 strengthened Rule 13's requirements with respect to the well integrity for wells that will be subjected to a hydraulic fracturing treatment, the Texas Railroad Commission's current rules do not equate the level of due diligence for injection of substances as part of a hydraulic fracturing treatment to the standards of due diligence mandated for operators of disposal wells or injection wells.[411] In addition, the Texas rules do not require the operator to obtain a report from an independent laboratory that confirms its analysis as to its well's integrity to confirm the operator's determination that the production zone that will be hydraulic fractured has a sufficient confining layer to prevent the migration of fluids to other zones.[412] In contrast to this lack of documentation requirement with respect to a well that will be hydraulically fractured, an operator who seeks a permit for either a disposal wells[413] or an injection well[414] must provide to the Texas Railroad Commission the geological evidence demonstrating that the formation is separated from freshwater formations by an impervious beds which provides adequate protection to such freshwater formations. Also, the operator in the context of disposal wells and injection wells must affirmatively provide an analysis of the available information that supports the operator's conclusion that no loss of zonal confinement will occur as part of the permit application.[415] Thus, in the context of disposal wells and injection wells, the Texas Railroad Commission requires the submission of data that could allow the agency (or another interested party) to verify the operator's conclusions, but in the hydraulic fracturing context this data is not required to be filed with the Texas Railroad Commission.

In addition, as a separate regulatory matter, Texas has recently amended its Rule 15 in order to reduce the scope of wells that are classified as inactive wells. In this regard, the prior Rule 15 defined an inactive well as a well that produced less than 10 barrels of oil per month for three consecutive months or produced less than 100,000 cubic feet of gas per month for three consecutive months.[416] In August 2016, the Texas Railroad Commission proposed to amend Rule 15's definition of an inactive well so that a well would be considered active if it produced 5 barrels of oil (not 10 barrels of oil) per month for three consecutive months and produced

410. *See generally* 16 TEX. ADMIN. CODE §§ 1.1-20.605 (2017).

411. *See generally id.*

412. *See generally id.*

413. *See id.* § 3.9(2), (3)(C) (The Railroad Commission also has discretion to increase the level of information needed to be filed further information at its discretion.).

414. *Id.* § 3.46(b)(1).

415. *Id.* § 3.9(2).

416. *Id.* § 3.15.

50,000 cubic feet (not 100,000 cubic feet) of gas per month for three consecutive months.[417] The Texas Railroad Commission explained that the reason for this change was to more accurately track inactive wells and reduce administrative burden and costs to the industry.[418] An important practical consequence of this rule change would be that it eliminates the need for companies to commence clean-up operations with respect to those wells that are no longer classified as inactive wells.[419] Oil and gas companies hailed this decision as one that would provide an economic boost to the industry and would relieve operators from a regulatory burden of having to properly plug these low-producing wells.[420] Even though the Texas Railroad Commission in its Sunset Report accepted that "failing to plug inactive wells can lead to pollution"[421] and in fact received a comment letter in its Rule 15 amendment process that expressed concern about this change to Rule 15. The letter claimed that the change could delay "site cleanup obligations to the detriment of land and mineral owners,"[422] the Texas Railroad Commission adopted its proposed Rule 15 amendment with only one change.[423] In fact, the Texas Railroad Commission stated that it had "determined that the repeals are not subject to Texas Government Code § 2001.0225 because they do not meet the definition of a 'major environmental rule' as defined in the Administrative Procedure Act" and therefore a regulatory analysis is not required.[424]

This statement represents a missed opportunity. Given the transformation that is occurring in the industry to re-focus its development efforts towards shale formations that underlie the heavily drilled conventional formations of the Permian Basin and elsewhere, the Texas Railroad Commission should require operators to conduct an environmental impact study to determine the impact of their hydraulic fracturing of new wells that are near abandoned wells, inactive wells, marginal wells, and orphaned wells. In addition, with respect to Rule 15, the Texas Railroad Commission should have addressed the concern expressed in this comment letter by imposing a requirement on operators of marginal wells to periodically test those wells to determine that these wells do not need remedial work to

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417. 41 Tex. Reg. 6311 (Aug. 26, 2016).

418. *Id.*

419. Comment Letter by Cyrus Reed, Conservation Dir., Lone Star Chapter of the Sierra Club, (Sept. 26, 2016) (on file with author).

420. Ryan Handy, *New Rule on Inactive Wells Could be a Game Changer for Small Energy Companies*, FUEL FIX (Nov. 16, 2016), http://fuelfix.com/blog/2016/11/16/new-rule-on-inactive-wells-could-be-a-game-changer-for-small-energy-companies/.

421. *See* TEX. R.R. COMM'N, SUNSET ADVISORY COMMISSION STAFF REPORT, 85th Legislature (2016-2017) at 12, https://www.sunset.texas.gov/public/uploads/files/reports/Railroad%20Commission%20of%20Texas%20Staff%20Report%20with%20Commission%20Decisions_0.pdf.

422. *See* Comment Letter by Laura Buchanan, Exec. Dir., Tex. Land & Mineral Owners Ass'n (Sept. 26, 2016) (on file with author).

423. 41 Tex. Reg. 9465 (Dec. 2, 2016).

424. 41 Tex. Reg. 6394-5 (Aug. 26, 2016).

maintain their structural integrity as a precondition for them to continue to operate these wells.

WEST VIRGINIA

In West Virginia, an operator is required to provide notice of its application for a horizontal well to the surface owner, any owner of a water source located within 1,500 feet of the well site, the owners of any coal seams that will be drilled through, and he or she must publish in a local newspaper and an official website the well location.[425] The operator is required to submit proof of service to all notice parties as part of its permit application.[426] West Virginia provides thirty days for all noticed parties to provide comments and written objections to an operator's well permit application,[427] and the regulatory agency is required to affirmatively review each written comment submitted by a noticed party prior to acting upon the permit application.[428] Thus, West Virginia provides a significant opportunity for affected parties to receive notice of a well permit application and to participate in the permitting process if desired.

The West Virginia rules require all well sites to be located more than one-thousand feet away from any public water supply[429] and at least one hundred feet away from any perennial stream, lake, pond or reservoir.[430] West Virginia does not require baseline water sampling, but conducting such testing allows the operator to rebut the presumption that any contaminates in a water supply pre-dated arose as a result of the operator's actions.[431] Also, the well site must be located at least three hundred feet away from any water source that contains trout.[432] Moreover, horizontal wells cannot be drilled within two hundred fifty feet of any known water well or developed spring used for human or domestic animal consumption.[433]

West Virginia also requires an operator to affirmatively investigate the area surrounding the proposed well pad so as to identify and evaluate potential conduits for unintended fracture propagation.[434] In this regard, the operator is required to identify and investigate all existing active, plugged, abandoned, and undocumented wells within a five hundred feet radius of the surface location of the well and within a five hundred feet radius of the lateral section of the wellbore.[435] The operator

425. W. VA. CODE R. § 22-6A-10 (2017).

426. *Id.* § 22-6A-11(b).

427. *Id.* § 22-6A-11(a).

428. *See id.* § 22-6A-11(c).

429. *Id.* § 22-6A-11(b).

430. *Id.*

431. *Id.* § 22-6A-18(b).

432. *Id.* § 22-6A-12(b).

433. *Id.* § 22-6A-12(a)

434. *Id.* § 22-6A-11(b).

435. *Id.* § 35-8-5.11.

is required to file a written report as part of its permit application that details its findings, and the report must explicitly address the potential impact to any wells that are reasonably expected to have penetrated a depth that could be within the range of the fracture propagation.[436]

West Virginia provides detailed rules that set forth specific requirements for well casing and cementing as part of the permit application, and the operator's report must document the operator's basis for concluding that the well's integrity will be maintained throughout the hydraulic fracturing process as part of the permit application process.[437]

With respect to injection wells, the West Virginia regulations require an operator to identify all abandoned wells, dry holes, surface water, water wells, and all known or suspected geological faults.[438] The operator is required to construct, test, and monitor the injection well in a manner so that its casing and cement will maintain integrity throughout its operation,[439] and the operator must demonstrate that the strata into which any injection well will inject must have an overlying confining bed that is free of known faults or fractures within the area of review.[440] West Virginia regulations contained detailed rules for the ongoing monitoring and reporting of an injection well.[441]

WYOMING

In Wyoming, an operator is required to submit groundwater baseline sampling data and a monitoring plan as part of the operator's application to obtain a drilling permit.[442] The groundwater monitoring plan must consist of initial baseline water sampling and testing followed by a series of subsequent sampling and testing that must be gathered after the operator has set the production casing or liner.[443] If four or fewer water sources are present within a one-half mile radius of the location of a proposed oil or gas well that will be hydraulically fractured, then the operator is required to collect baseline water samples from each available water source.[444] If more than four water sources exist within a one-half mile radius of the proposed well, then the operator must submit a baseline sampling plan for pre-approval that considers proximity, whether separate aquifers are within this one-half mile radius, and a consideration of the groundwater in the vicinity.[445] The operator is required

436. *Id.*

437. *See id.* § 22-6A-24.

438. *Id.* § 47-13-8.5.a.2.

439. *Id.* § 47-13-8.2.a.

440. *Id.* § 47-13-8.2.a.

441. *See generally id.* § 47-13-8.4.

442. 55-3 WYO. CODE R. § 46(a) (LexisNexis 2017).

443. *Id.*

444. *Id.* § 46(b).

445. *Id.* § 46(c).

to conduct the baseline water sampling within twelve months prior to the spudding of the first well on a multi-pad site.[446] The operator is then required to conduct subsequent sampling within twelve months to twenty-four months after setting the well's production casing or liner.[447] A second subsequent sampling and testing must be conducted between thirty-six and forty-eight months after setting the production casing or liner.[448] And, the second subsequent sampling must be conducted at least twenty-four months after the first subsequent sampling.[449] All of the above sampling, analysis, and evaluation and reporting are to be done in accordance with an established protocol set forth in an appendix to the Wyoming regulations,[450] and the regulations themselves contain a detailed list of requirements for the testing process.[451] The operator is required to provide copies of all laboratory analytical results to the Wyoming Oil and Gas Conservation Commissioner and also to all owners of the adjacent water sources within three months of the sample collection date.[452] All analytical results and spatial coordinates of the available water source will be made available to the public unless the data is otherwise considered confidential under Wyoming law.[453] If any of the analysis of any water sampling tests indicates the existence of thermogenic or a mixture of thermogenic and biogenic gas in the water supply, then the operator has an immediate obligation to notify both the Wyoming's Department of Environmental Quality and also the water source owner within twenty-four hours.[454]

Wyoming regulations for disposal wells require a similar review process that ensures the well integrity of the disposal well, the location of any potential faults or other wells within a one-half mile of the disposal well and imposes a similar affirmative duty to provide notice to affected parties prior to the approval of the injection well permit.[455]

446. *Id.* § 46(e).
447. *Id.*
448. *Id.*
449. *Id.*
450. *Id.* § 46(f).
451. *See id.* § 46(h).
452. *Id.* § 46(g).
453. *Id.*
454. *Id.* § 46(j).
455. *See generally* 55-4 WYO. CODE R. § 5 (LexisNexis 2017).